The following represents the balances of the asset retirement obligation as of December 31, 2005, 2004 and 2003,and the additions, accretion, settlements and translation adjustments of the asset retirement obligation for the years ended December 31, 2005 and 2004. The asset retirement obligation is included in other long-term obligations in the consolidated balance sheet.

	Reorganized NRG							
	Northeast	South Central	Australia	Other International	Alternative Energy	Non Generation	Other	Total Asset Retirement Obligation
	(In millions)							
Balance as of December 31, 2003	$ 12	$ 3	$ 9	$ 4	$ 1	$ 1	$ —	$ 30
Additions	1	—	3	—	—	—	—	4
Accretion	—	—	2	—	—	—	—	2
Balance as of December 31, 2004	13	3	14	4	1	1	—	36
Additions	1	—	—	—	—	—	4	5
Accretion	1	—	1	—	—	—	—	2
Translation adjustments	—	—	(1)	—	—	—	—	(1)
Balance as of December 31, 2005	$ 15	$ 3	$ 14	$ 4	$ 1	$ 1	$ 4	$ 42

Prior to December 5, 2003, we completed our annual review of asset retirement obligations. As part of that review we made revisions to our previously recorded obligation in the amount of $4 million. The revisions included identification of new obligations as well as changes in costs required at retirement date. As a result of adopting Fresh Start we revalued our asset retirement obligations on December 6, 2003. We recorded an additional asset retirement obligation of approximately $7 million in connection with Fresh Start reporting. This amount results from a change in the discount rate used between adoption and Fresh Start reporting as of December 5, 2003, equal to 500 to 600 basis points.

Note 10 — Inventory

Inventory, which is stated at the lower of weighted average cost or market, consists of:

	Reorganized NRG	
	December 31, 2005	December 31, 2004
	(In millions)	
Fuel oil	$ 132	$ 114
Coal	66	75
Natural gas	4	—
Spare parts	54	53
Other	4	5
Total inventory	$ 260	$ 247

Note 11 — Notes Receivable and Capital Lease

Notes receivable consist primarily of fixed and variable rate notes secured by equity interests in partnerships and joint ventures. The notes receivable and capital lease are as follows:

	Reorganized NRG	
	December 31, 2005	December 31, 2004
	(In millions)	
Notes Receivable — non-affiliate		
Omega Energy, LLC, due 2004, 12.5%	$ —	$ 4
Omega Energy II, LLC, due 2009, 11%	—	1
Elk River — Great River Energy, due December 31, 2008, 4.69%	1	1
Northbrook Texas LLC, due February 2024, 9.25%	—	9
Termo Rio (via NRGenerating Luxembourg (No. 2) S.a.r.l), 8.0%	—	57
Capital Lease		
VEAG Vereinigte Energiewerke AG, due August 31, 2021, 13.88% (direct financing lease)[1]	379	461
Notes receivable and capital lease — non-affiliates	380	533
Reserve for uncollectible notes receivable	—	(8)
Notes receivable non-affiliates and capital lease, net	380	525
Less current maturities	25	85
Total	$ 355	$ 440
Notes Receivable — affiliates		
NEO notes to various affiliates due primarily 2012, prime +2%	—	4
Kraftwerke Schkopau GBR, indefinite maturity date, 4.75%-7.79%[2]	103	120
Notes receivable — affiliates	$ 103	$ 124

(1) Saale Energie GmbH, or Saale, has sold 100% of its share of capacity from the Schkopau power plant to VEAG Vereinigte Energiewerke AG under a 25-year contract, which is more than 83% of the useful life of the plant. The direct financing lease receivable amount was calculated based on the present value of the income to be received over the life of the contract.

(2) Saale entered into a note receivable with Kraftwerke Schkopau GBR, a partnership between Saale and E.On Kraftwerke GmbH. The note was used to fund Saale's initial capital contribution to the partnership and to cover project liquidity shortfalls during construction of a power plant. The note is subject to repayment upon the disposition of the Schkopau plant.

Note 12 — Property, Plant and Equipment

The major classes of property, plant and equipment were as follows:

	Depreciable Lives	Reorganized NRG December 31, 2005	Reorganized NRG December 31, 2004	Average Remaining Useful Life
		(In millions)		
Facilities and equipment	1-42 Years	$ 3,223	$ 3,199	14
Land and improvements		128	127	
Office furnishings and equipment	2-10 Years	26	21	3
Construction in progress		54	17	
Total property, plant and equipment		3,431	3,364	
Accumulated depreciation		(392)	(206)	
Net property, plant and equipment		$ 3,039	$ 3,158	

Note 13 — Investments Accounted for by the Equity Method

We have investments in various international and domestic energy projects. The equity method of accounting is applied to such investments in affiliates, which include joint ventures and partnerships, because the ownership structure prevents us from exercising a controlling influence over operating and financial policies of the projects. Under this method, equity in pretax income or losses of domestic partnerships and, generally, in the net income or losses of international projects, are reflected as equity in earnings of unconsolidated affiliates.

A summary of certain of our more significant equity-method investments, which were in operation at December 31, 2005, is as follows:

Name	Geographic Area	Economic Interest
MIBRAG mbH, or MIBRAG	Germany	50%
Saguaro Power Company, or Saguaro	USA	50%
Rocky Road Power	USA	50%
Enfield Energy Centre Limited, or Enfield — sold on April 1, 2005	UK	25%
West Coast Power, or WCP	USA	50%
James River	USA	50%
Gladstone Power Station, or Gladstone	Australia	37.5%
Central and Eastern European Energy Power Fund	Various	22.2%
Scudder LA Power Fund I	Latin America	25%

During 2005 we sold our equity investment in Enfield. During 2004, we sold our equity investments in Commonwealth Atlantic Limited Partnership, four NEO investments (Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC and NEO Montauk Gasco LLC), Calpine Cogeneration, Loy Yang, Kondapalli, and ECKG. Summarized financial information for investments in unconsolidated affiliates accounted for under the equity method is as follows:

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
Summarized Statements of Operations				
Operating revenues	$ 1,300	$ 2,428	$ 268	$ 2,212
Costs and expenses	1,101	1,966	203	2,036
Net income	$ 199	$ 462	$ 65	$ 176
Summarized Balance Sheets				
Current assets	$ 592	$ 845	$ 830	$ 784
Non-current assets	2,561	2,903	6,541	6,452
Total assets	$ 3,153	$ 3,748	$ 7,371	$ 7,236
Current liabilities	133	206	1,276	1,216
Non-current liabilities	1,143	1,740	3,592	3,529
Equity	1,877	1,802	2,503	2,491
Total liabilities and equity	$ 3,153	$ 3,748	$ 7,371	$ 7,236
NRG's share of equity and net income				
NRG's share of equity	$ 810	$ 809	$ 1,052	$ 1,079
NRG's share of net income	$ 104	$ 160	$ 14	$ 171

We have ownership interests in five companies that were considered significant as defined by applicable SEC regulations as of December 31, 2005: MIBRAG, WCP, Saguaro, Gladstone and Enfield. We account for our investments using the equity method. Our carrying value of equity investments is impacted by impairments, unrealized gains and losses on derivatives and movements in foreign currency exchange rates as well as other adjustments. The financial statements of MIBRAG and WCP will be filed as separate exhibits to this Form 10-K.

MIBRAG Summarized Financial Information

The Company owns a 50% interest in MIBRAG. Located near Leipzig, Germany, MIBRAG owns and manages a coal mining operation, three lignite fueled power generation facilities and other related businesses. Approximately 50% of the power generated by MIBRAG is used to support its mining operations, with the remainder sold to a German utility company. A portion of the coal from MIBRAG's mining operation is used to fuel the power generation facilities, but a majority of the mined coal is sold primarily to two major customers, including Schkopau, an affiliate of the Company. A significant portion of the sales of MIBRAG are made pursuant to long-term coal and energy supply contracts. The following tables summarize financial information for MIBRAG, including interests owned by the Company and other parties for the periods shown below:

Results of Operations

	For the Year Ended		
	2005	2004	2003
	(In millions)		
Operating revenues	$ 432	$ 427	$ 401
Operating income	72	61	62
Net income (pre-tax)	51	43	46

Financial Position

	December 31,	
	2005	2004
	(In millions)	
Current assets	$ 121	$ 179
Other assets	1,134	1,295
Total assets	$ 1,255	$ 1,474
Current liabilities	$ 22	$ 21
Other liabilities	885	1,083
Equity	348	370
Total liabilities and equity	$ 1,255	$ 1,474

For the years ended December 31, 2005 and 2004, the period from December 6, 2003 to December 31, 2003 and the period from January 1, 2003 through December 5, 2003 our equity earnings from MIBRAG were approximately $26 million, $21 million, $0 million and $22 million, respectively.

As discussed in Note 2, our MIBRAG equity investment will be negatively affected by EITF 04-6. Currently, MIBRAG has an asset totaling € 157 million, approximately $185 million, representing the stripping costs incurred during production as of December 31, 2005. Following adoption in the first quarter of 2006, our investment in MIBRAG will be reduced by 50% of the above mentioned asset, approximately $93 million, with an offsetting charge to retained earnings.

West Coast Power LLC Summarized Financial Information

We have a 50% interest in WCP. Upon adoption of Fresh Start we adjusted our investment in WCP to fair value as of December 6, 2003. In accordance with APB 18, we have reconciled the value of our investment as of December 6, 2003 to our share of WCP's partner's equity. As a result of pushing down the impact of Fresh Start to the project's balance sheet, we determined that a contract based intangible asset with a one year remaining life, consisting of the value of WCP's CDWR energy sales contract, must be established and recognized as a basis adjustment to our share of the future earnings generated by WCP. This adjustment reduced our equity earnings in the amount of approximately $116 million for the year ended December 31, 2004 until the contract expired in December 2004. Offsetting this reduction in earnings is a favorable adjustment to reflect a lower depreciation expense resulting from the corresponding reduced value of the project's fixed assets from Fresh Start reporting.

During the year ended December 31, 2005 we recorded equity earnings of $22 million for WCP after adjustments for the reversal of $12 million project-level depreciation expense. For the year ended December 31, 2004 we recorded equity earnings of approximately $69 million for WCP after adjustments for the reversal of approximately $32 million project-level depreciation expense, offset by a decrease in earnings related to approximately $116 million amortization of the intangible asset for the CDWR contract. During the period December 6, 2003 through December 31, 2003 we recorded equity earnings of approximately $9 million for WCP after adjustments for the reversal of approximately $3 million project-level depreciation expense, offset by a decrease in earnings related to approximately $9 million amortization of the intangible asset for the CDWR contract. The following table summarizes financial information for WCP, including interests owned by us and other parties for the periods shown below:

Results of Operations

	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
		(In millions)		
Operating revenues	$ 301	$ 726	$ 53	$ 643
Operating income	15	303	31	201
Net income (pre-tax)	21	306	31	202

Financial Position

	December 31, 2005	December 31, 2004
	(In millions)	
Current assets	$ 312	$ 426
Other assets	376	394
Total assets	$ 688	$ 823
Current liabilities	43	82
Other liabilities	6	5
Equity	639	736
Total liabilities and equity	$ 688	$ 823

For the years ended December 31, 2005 and 2004, the period from December 6, 2003 to December 31, 2003 and the period from January 1, 2003 through December 5, 2003 our equity earnings from WCP were approximately $22 million, $69 million, $9 million and $99 million, respectively.

Acquisition of Remaining 50% in WCP from Dynegy, Inc. and sale of our 50% investment in Rocky Road Power LLC

On December 27, 2005, we entered into purchase and sale agreements for projects co-owned with Dynegy, Inc., or Dynegy. Under the agreements, we will acquire Dynegy's 50% ownership interest in WCP (Generation) Holdings, Inc., and become the sole owner of WCP's 1,808 MW of generation in Southern California.In addition, we are selling to Dynegy our 50% ownership interest in Rocky Road Power LLC, or Rocky Road, a 330 MW gas-fueled, simple cycle peaking plant located in Dundee, Illinois. Both of these transactions are conditioned upon one another and we will pay Dynegy a net purchase price of $160 million at closing. We will fund the net purchase price with cash held by WCP. We anticipate closing both transactions during the first quarter of 2006.

Saguaro Power Company

NRG purchased 50 percent of Saguaro in September 2001. Located in Henderson, near Las Vegas, Nevada, the Saguaro plant is a cogeneration plant with dual-fuel capability (natural gas and oil) and has contracted its electricity to Nevada Power through 2022, one steam host (Pioneer) whose contract expires in 2007 (with a negotiated renewal) and a steam off taker (Ocean Spray), whose contract runs through 2015. Upon adoption of Fresh Start we created a basis difference as we increased our investment in Saguaro by approximately $31 million to reflect fair value as of December 6, 2003. From Fresh Start we have amortized this amount by approximately $2 million annually based on the plant's estimated remaining useful life, recorded as a reduction in equity earnings. In accordance with APB 18, we have reconciled the value of our investment as of December 6, 2003 to our share of Saguaro's partner's equity.

The Saguaro plant had a long-term gas supply agreement that expired in July 2005 and the plant is now exposed to the monthly spot gas market. At present, Saguaro cannot pass higher natural gas costs through to its customers, and the plant is currently experiencing negative cash flows. Due to this event and based on forecasted prices and cash flows, we determined that we have a permanent decline in value of our 50% interest and recorded a write down of our equity investment in Saguaro by approximately $27 million (see also Note 7). As such, the remaining basis difference as of December 31, 2005 is immaterial.

For the years ended December 31, 2005 and 2004, the period from December 6, 2003 to December 31, 2003 and the period from January 1, 2003 through December 5, 2003 our equity earnings from Saguaro were approximately $0 million, $5 million, $1 million and $4 million, respectively.

Gladstone

We own a 37.5% interest in Gladstone, an unincorporated joint venture, or UJV, which operates a 1,613 megawatt coal-fueled power generation facility in Queensland, Australia. The power generation facility is managed by the joint venture participants and the facility is operated by NRG. Operating expenses incurred in connection with the operation of the facility are funded by each of the participants in proportion to their ownership interests. Coal is sourced from a mining operation owned and operated by certain joint venture partners and other investors under a long term supply agreement. We and the joint venture participants receive a majority of our respective share of revenues directly from customers and are directly responsible and liable for project related debt, all in proportion to the ownership interests in the UJV. Power generated by the facility is primarily sold to an adjacent aluminum smelter, with excess power sold on the national market.

For the years ended December 31, 2005 and 2004, the period from December 6, 2003 to December 31, 2003 and the period from January 1, 2003 through December 5, 2003 our equity earnings from Gladstone were approximately $24 million, $18 million, $1 million and $12 million, respectively.

Enfield Energy Centre Limited

Until April 1, 2005, we owned a 25% interest in Enfield, located in Enfield, North London, UK. Enfield owns and operates a 396 MW, natural gas-fired combined cycle gas turbine power station. Enfield sells electricity generated from the plant in North London and the gas generated from the plant under a long-term gas supply contract. As of April 1, 2005, Enfield had a long-term agreement that effectively fixed the purchase price of its gas supply. The purpose of the contract, which was executed in August 1997 and extended through October 2014, was to mitigate the risk associated with fluctuations in the price of gas utilized in the generation of electricity at our facility. This contract was considered a derivative as defined by SFAS 133, and was afforded mark-to-market accounting treatment. We were subject to volatility in earnings associated with fluctuations in the market price of gas. Enfield has the ability to consume the gas for generation, and therefore our risk of loss associated with the contract is minimal. Given an increase in the price of natural gas in the UK market during the course of 2004 and 2005, we recorded mark to market gains of approximately $12 million and $23 million for the three months ended March 31, 2005 and for the year ended December 31, 2004, respectively.

For the three months ended March 31, 2005, the year ended December 31, 2004, the period from December 6, 2003 to December 31, 2003 and the period from January 1, 2003 through December 5, 2003 our equity earnings from Enfield were approximately $16 million, $29 million, $0 million and $6 million, respectively.

Note 14 — Intangible Assets

Reorganized NRG

Upon the adoption of Fresh Start, we established certain intangible assets for power sales agreements and plant emission allowances. These intangible assets are being amortized over their respective lives based on a straight-line or units of production basis to resemble our realization of such assets. We are also actively selling part of our emission allowances and their respective cost is expensed when sold.

Power sale agreements are amortized as a reduction to revenue over the terms and conditions of each contract. The weighted average remaining amortization period is two years for the power sale agreements. Emission allowances are amortized as additional fuel expense based upon the actual level of emissions from the respective plants through 2023. Aggregate amortization recognized for the year ended December 31, 2005, December 31, 2004 and the period December 6, 2003 to December 31, 2003 was approximately $24 million, $50 million and $5 million, respectively. The annual aggregate amortization for each of the five succeeding years, starting with 2006, is expected to approximate $14 million in 2006, $12 million in 2007, $11 million in 2008, $11 million in 2009 and $8 million for 2010 for both the power sale agreements and emission allowances. The expected annual amortization of these amounts is expected to change as we continue to sell part of our emission allowances and as we relieve our tax valuation allowance per the explanation below.

For the year ended December 31, 2005, we reduced our valuation allowance by approximately $17 million and reduced certain deferred tax assets by $9 million. Both movements were offset to our intangible assets at our wholly-owned subsidiaries, in accordance with SOP 90-7. For the year ended December 31, 2004, we reduced our deferred tax valuation allowance by $64 million and recorded a corresponding reduction of $55 million related to our intangible assets at our wholly-owned subsidiaries. The remaining $9 million was recorded as a reduction to our intangible asset related to our equity investments in West Coast Power. In accordance with SOP 90-7, any future income tax benefits realized from reducing the valuation allowance should first reduce intangible assets until exhausted, and thereafter be recorded as a direct addition to paid-in capital. During 2004, Intangible assets were also reduced by approximately $33 million consisting of an approximate $11 million reduction in connection with the recognition of certain tax credits to be claimed on our New York state franchise tax return and approximately $22 million of adjustments related to a true-up of certain other tax evaluations and the recognition of Itiquira Energetica S.A. preferred stock as debt for U.S. generally accepted accounting purposes.

Intangible assets consisted of the following:

	Power Sale Agreements	Emission Allowances	Total
		(In millions)	
Original balance as of December 6, 2003	$ 64	$ 373	$ 437
Amortization	(5)	—	(5)
Balance as of December 31, 2003	59	373	432
Tax valuation adjustments	(5)	(50)	(55)
Other valuation adjustments	(2)	(31)	(33)
Amortization	(32)	(18)	(50)
Balance as of December 31, 2004	20	274	294
Tax valuation adjustments	(1)	(16)	(17)
Other valuation adjustments	—	9	9
Sale of emission credits to 3rd parties	—	(5)	(5)
Amortization	(12)	(12)	(24)
Balance as of December 31, 2005	$ 7	$ 250	$ 257

Predecessor Company

We had intangible assets that were amortized and consisted of service contracts. Aggregate amortization expense for the period January 1, 2003 to December 5, 2003 was approximately $4 million.

Note 15 — Accounting for Derivative Instruments and Hedging Activities

SFAS No. 133 *"Accounting for Derivative Instruments and Hedging Activities"*, or SFAS No. 133, as amended, requires us to recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. If certain conditions are met, we may be able to designate our derivatives as cash flow hedges and defer the effective portion of the change in fair value of the derivatives in Accumulated Other Comprehensive Income, or OCI and subsequently recognize in earnings when the hedged items impact income. The ineffective portion of a cash flow hedge is immediately recognized in income.

For derivatives designated as hedges of the fair value of assets or liabilities, the changes in fair value of both the derivatives and the hedged items are recorded in current earnings. The ineffective portion of a hedging derivative instrument's change in fair values will be immediately recognized in earnings.

For derivatives that are neither designated as cash flow hedges or do not qualify for hedge accounting treatment, the changes in the fair value will be immediately recognized in earnings. Under the guidelines established by SFAS No. 133, as amended, certain derivative instruments may qualify for the normal purchase and sale exception and are therefore exempt from fair value accounting treatment. SFAS No. 133 applies to our energy related commodity contracts, interest rate swaps and foreign exchange contracts.

As the Company engages principally in the trading and marketing of its generation assets, most of our commercial activities qualify for hedge accounting under the requirements of SFAS No. 133. In order to so qualify, the physical generation and sale of electricity must be highly probable at inception of the trade and throughout the period it is held, as is the case with our base-load coal plants. For this reason, trades in support of the company's peaking units will not generally qualify for hedge accounting treatment and any changes in fair value are likely to be reflected on a mark-to-market basis in the statement of operations. The majority of trades in support of our base-load coal units will normally qualify for hedge accounting treatment and any fair value movements will be reflected in the balance sheet as part of OCI.

Derivative Financial Instruments

Energy Related Commodities

As part of our risk management activities, we manage the commodity price risk associated with our competitive supply activities and the price risk associated with power sales from our electric generation facilities. In doing so, we may enter into a variety of derivative and non-derivative instruments, including but not limited to the following:

- Forward contracts, which commit us to purchase or sell energy commodities in the future.
- Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument.
- Swap agreements, which require payments to or from counter-parties based upon the differential between two prices for a predetermined contractual (notional) quantity.
- Option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

The objectives for entering into such hedges include:

- Fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on our electric generation operations.
- Fixing the price of a portion of anticipated fuel purchases for the operation of our power plants.
- Fixing the price of a portion of anticipated energy purchases to supply our load-serving customers.

Ineffectiveness will result from a difference in the relative price movements between a financial transaction and the underlying physical pricing point. If this difference is large enough, it will cause an entity to discontinue the use of hedge accounting.

At December 31, 2005 we had hedge and non-hedge energy related commodities financial instruments extending through December 2026. At December 31, 2005 our derivative assets and liabilities consisted primarily of the following:

- Forward and financial contracts for the sale of electricity and related products economically hedging our generation assets forecasted output through 2008.
- Forward and financial contracts for the purchase of fuel commodities relating to the forecasted usage of our generation assets into 2006.

Also, at December 31, 2005 we had other energy related contracts that did not qualify as derivatives under the guidelines established by SFAS No. 133, or we elected to apply the normal purchase and sale exception as follows:

- Coal purchase contracts extending through 2009 designated as normal purchases and disclosed as part of our contractual cash obligations. (See Note 25 Commitments and Contingencies).
- Natural gas transportation and storage agreements these contracts are not derivatives and are disclosed as part of our contractual cash obligations. (See Note 25 Commitments and Contingencies).
- Load-following forward electric sales contracts extending through 2026 (these contracts are not considered derivatives).

For the year ended December 31, 2005, the impact of hedge ineffectiveness associated with financial forward contracted electric sales was immaterial. No ineffectiveness was recognized on commodity cash flow hedges during the year ended December 31, 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003.

Our pre-tax earnings for the year ended December 31, 2005 and 2004, the period December 6, 2003 through December 31, 2003, and the period January 1, 2003 through December 5, 2003 were affected by an unrealized loss of $143 million, an unrealized gain of $81 million, an unrealized loss of $1 million and an unrealized gain of $54 million respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

During the year ended December 31, 2005 and 2004, we reclassified losses of $132 million and $3 million, respectively, from OCI to current period earnings. During the period December 6, 2003 through December 31, 2003 no gains or losses were reclassified from OCI to current-period earnings. Our plan of reorganization became effective December 5, 2003 and, accordingly, we made adjustments for Fresh Start in accordance with SOP 90-7. These Fresh Start adjustments resulted in a write-off of net gains recorded in OCI of $61 million on energy related derivative instruments accounted for as hedges. During the period January 1, 2003 through December 5, 2003, we reclassified gains of $113 million from OCI to current period earnings. We expect to reclassify an additional $208 million of deferred losses to earnings during the next twelve months on energy related derivative instruments accounted for as hedges.

Interest Rates

To manage interest rate risk, we have entered into interest rate swap agreements that fix the interest payments or the fair value of selected debt issuances. The qualifying swap agreements are accounted for as cash flow or fair value hedges. The effective portion of the cash flow hedges' cumulative gains/losses are reported as a component of OCI in stockholders' equity. These gains/losses are recognized in earnings as the hedged interest expense is incurred. The reclassification from OCI is included on the same line of the statement of operations in which the hedged item appears. The entire amount of the change in fair value hedges is recorded in the statement of operations along with the change in value of the hedged item. At December 31, 2005 our consolidating subsidiaries had various interest-rate swap agreements extending through June 2019 with combined notional amounts of $1.2 billion. If these swaps had been terminated at December 31, 2005 we would have owed the counter-parties $33 million.

At December 31, 2005 all of our interest rate swap arrangements have been designated as either cash flow or fair value hedges.

No ineffectiveness was recognized on interest rate swaps that qualify as hedges during the year ended December 31, 2005 and 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003.

Our pre-tax earnings for the year ended December 31, 2005 were not affected by changes in the fair value of interest rate derivative instruments not accounted for as hedges in accordance with SFAS No. 133. Our pre-tax earnings for the year ended December 31, 2004 were increased by an unrealized gain of less than a million dollars associated with changes in the fair value of interest rate derivative instruments not accounted for as hedges in accordance with SFAS No. 133. One of these instruments was a $400 million swap to pay fixed, which was not designated as a hedge of the expected cash flows at March 31, 2004. As of April 1, 2004, this instrument was designated as a cash flow hedge under SFAS No. 133. As a result, changes in value subsequent to April 1, 2004 are deferred and recorded as part of OCI.

Our pre-tax earnings for the period December 6, 2003 through December 31, 2003 and the period January 1, 2003 through December 5, 2003 were increased by an unrealized gain of $2 million and decreased by an unrealized loss of $15 million, respectively, associated with changes in the fair value of interest rate derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

During the year ended December 31, 2005, we reclassified gains of $2 million from OCI to current period earnings. During the year ended December 31, 2004, we reclassified losses of $5 million from OCI to current period earnings. During the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003, losses of $0 and $30 million, respectively, were reclassified from OCI to current-period earnings. Our plan of reorganization became effective December 5, 2003 and, accordingly, we made adjustments for Fresh Start in accordance with SOP 90-7. These Fresh Start adjustments resulted in a write-off of net losses recorded in OCI of $66 million on interest rate swaps accounted for as hedges. We expect to reclassify $2 million of deferred gains to earnings during the next twelve months associated with interest rate swaps accounted for as hedges.

Foreign Currency Exchange Rates

To preserve the U.S. dollar value of projected foreign currency cash flows, we may hedge, or protect those cash flows if appropriate foreign hedging instruments are available. As of December 31, 2005, the results of any outstanding foreign currency exchange contracts were immaterial to our financial results.

No ineffectiveness occurred on foreign currency cash flow hedges during the year ended December 31, 2004, the periods December 6, 2003 through December 31, 2003 or January 1, 2003 through December 5, 2003.

During the year ended December 31, 2005 and 2004 and the period December 6, 2003 to December 31, 2003, our pre-tax earnings were not affected by any gain or loss associated with foreign currency hedging instruments not accounted for as hedges in accordance with SFAS No. 133.

During the year ended December 31, 2005 and 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003, no amounts were reclassified from OCI to current period earnings. Our plan of reorganization became effective December 5, 2003 and, accordingly, we made adjustments for Fresh Start in accordance with SOP 90-7. These Fresh Start adjustments resulted in a write-off of net losses recorded in OCI of less than one million dollars on foreign currency swaps accounted for as hedges. Any amounts we expect to reclassify to earnings during the next twelve months on foreign currency swaps accounted for as hedges are immaterial to our results.

Accumulated Other Comprehensive Income

The following table summarizes the effects of SFAS No. 133, as amended, on our other comprehensive income balance attributable to hedged derivatives for the year ended December 31, 2005 before income taxes:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(losses) in millions)			
Accumulated OCI balance at December 31, 2004	$ 5	$ 2	$ —	$ 7
Unwound from OCI during period:				
— due to unwinding of previously deferred amounts	132	(2)	—	130
Mark to market of hedge contracts	(341)	8	—	(333)
Accumulated OCI balance at December 31, 2005	$ (204)	$ 8	$ —	$ (196)
Gains/(Losses) expected to unwind from OCI during next 12 months	$ (208)	$ 2	$ —	$ (206)

During the year ended December 31, 2005, losses of approximately $130 million were reclassified from OCI to current period earnings due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded. Also during the year ended December 31, 2005, we recorded a loss in OCI of $333 million related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to SFAS No. 133 as of December 31, 2005 was an unrecognized loss of approximately $196 million. We expect $206 million of deferred net losses on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

The following table summarizes the effects of SFAS No. 133, as amended, on our other comprehensive income balance attributable to hedged derivatives for the year ended December 31, 2004 before income taxes

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(losses) in millions)			
Accumulated OCI balance at December 31, 2003	$ (2)	$ 1	$ —	$ (1)
Unwound from OCI during period:				
— due to unwinding of previously deferred amounts	3	5	—	8
Mark to market of hedge contracts	4	(4)	—	—
Accumulated OCI balance at December 31, 2004	$ 5	$ 2	$ —	$ 7

During the year ended December 31, 2004, losses of approximately $8 million were reclassified from OCI to current period earnings due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded. Also during the year ended December 31, 2004, we recorded a loss in OCI of less than $1 million related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to SFAS No. 133 as of December 31, 2004 was an unrecognized gain of approximately $7 million.

The following table summarizes the effects of SFAS No. 133, as amended, on our other comprehensive income balance attributable to hedged derivatives for the period December 6, 2003 to December 31, 2003 before income taxes:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(losses) in millions)			
Accumulated OCI balance at December 6, 2003	$ —	$ —	$ —	$ —
Unwound from OCI during period:				
— due to unwinding of previously deferred amounts	—	—	—	—
Mark to market of hedge contracts	(2)	1	—	(1)
Accumulated OCI balance at December 31, 2003	$ (2)	$ 1	$ —	$ (1)

During the period ended December 31, 2003, we recorded a loss in OCI of approximately $1 million related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to SFAS No. 133, as amended, as of December 31, 2003 was an unrecognized loss of approximately $1 million.

The following table summarizes the effects of SFAS No. 133, as amended, on our other comprehensive income balance attributable to hedged derivatives for the period January 1, 2003 to December 5, 2003 before income taxes:

	Predecessor Company			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(losses) in millions)			
Accumulated OCI balance at December 31, 2002	$ 130	$ (103)	$ —	$ 27
Unwound from OCI during period:				
— due to forecasted transactions probable of no longer occurring	—	32	—	32
— due to unwinding of previously deferred amounts	(113)	(2)	—	(115)
Mark to market of hedge contracts	44	7	—	51
Accumulated OCI balance at December 5, 2003	61	(66)	—	(5)
— due to Fresh Start reporting write-off	(61)	66	—	5
Accumulated OCI balance at December 6, 2003	$ —	$ —	$ —	$ —

During the period ended December 5, 2003, we reclassified losses of $32 million from OCI to current-period earnings as a result of the discontinuance of cash flow hedges because it is probable that the original forecasted transactions will not occur by the end of the originally specified time period. Additionally, gains of $115 million were reclassified from OCI to current period earnings during the period ended December 5, 2003 due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded. Also during the period ended December 5, 2003, we recorded a gain in OCI of approximately $51 million related to changes in the fair values of derivatives accounted for as hedges. Our plan of reorganization became effective December 5, 2003 and, accordingly, we made adjustments for Fresh Start in accordance with SOP 90-7. These Fresh Start adjustments resulted in a write-off of net losses recorded in OCI of $5 million.

Statement of Operations

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the year ended December 31, 2005:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(losses) in millions)			
Revenue from majority-owned subsidiaries	$ (145)	$ —	$ —	$ (145)
Cost of operations	2	—	—	2
Other income	—	—	—	—
Equity in earnings of unconsolidated subsidiaries	—	—	—	—
Interest expense	—	—	—	—
Total Statement of Operations impact before tax	$ (143)	$ —	$ —	$ (143)

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the year ended December 31, 2004:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(losses) in millions)			
Revenue from majority-owned subsidiaries	$ 57	$ —	$ —	$ 57
Cost of operations	—	—	—	—
Other income	—	—	—	—
Equity in earnings of unconsolidated subsidiaries	24	—	—	24
Interest expense	—	—	—	—
Total Statement of Operations impact before tax	$ 81	$ —	$ —	$ 81

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the period from December 6, 2003 through December 31, 2003:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(losses) in millions)			
Revenue from majority-owned subsidiaries	$ (1)	$ —	$ —	$ (1)
Cost of operations	1	—	—	1
Other income	—	—	—	—
Equity in earnings of unconsolidated subsidiaries	(1)	—	—	(1)
Interest expense	—	2	—	2
Total Statement of Operations impact before tax	$ (1)	$ 2	$ —	$ 1

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the period from January 1, 2003 through December 5, 2003:

	Predecessor Company			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(losses) in millions)			
Revenue from majority-owned subsidiaries	$ 30	$ —	$ —	$ 30
Cost of operations	5	—	—	5
Other income	—	—	—	—
Equity in earnings of unconsolidated subsidiaries	19	—	—	19
Interest expense	—	(15)	—	(15)
Total Statement of Operations impact before tax	$ 54	$ (15)	$ —	$ 39

Note 16 — Other Bankruptcy Settlements

A principal component of our plan of reorganization is a settlement with Xcel Energy in which Xcel Energy agreed to make a contribution consisting of cash (and, under certain circumstances, its stock) in the aggregate amount of up to $640 million to be paid in three separate installments following the effective date of our plan of reorganization, that was received during 2004. The Xcel Energy settlement agreement resolves any and all claims existing between Xcel Energy and us and/or our creditors and, in exchange for the Xcel Energy contribution, Xcel Energy received a complete release of claims from us and our creditors, except for a limited number of creditors who have preserved their claims as set forth in the confirmation order entered on November 24, 2003. We used the proceeds from the Xcel Energy settlement to pay off our creditor pool obligation as of December 31, 2004.

In addition, our other bankruptcy settlement obligation as of December 31, 2005 and 2004 was $3 million and $6 million, respectively. This obligation relates to the allowed claims against NRG Energy related to our Pike facilities. See Note 25 — NRG FinCo Settlement. The net change in the balance of $3 million reflects the sale of certain of these assets, the proceeds of which were paid to the FinCo lenders.

Note 17 — Debt and Capital Leases

Long-term debt and capital leases consist of the following:

			Reorganized NRG			
			Principal	Fair Value Adjustment	Principal	Fair Value Adjustment
	Stated Rate	Effective Rate	December 31, 2005	December 31, 2005	December 31, 2004	December 31, 2004
	(Percent)		(In millions)			
NRG Recourse Debt:						
NRG Energy 2nd priority senior notes, due December 15, 2013(3)(4)	8.00%	n/a	$ 1,080	$ (6)	$ 1,725	$ 10
NRG Amended Credit Facility, due December 24, 2011	(1)	—	795	—	800	—
NRG Promissory Note, Xcel Energy, due June 5, 2006	3.00	9.00	10	—	10	(1)
NRG Project-Level, Non-Recourse Debt:						
NRG Peaker Finance Co. LLC, due June 2019	(1)	L+3.5(2)	297	(57)	301	(64)
Flinders Power Finance Pty, due September 2012	(1)	—	177	—	203	10
NRG Energy Center Minneapolis LLC, Senior secured notes, due 2013 and 2017, 7.12%-7.31%	(1)	L+2(2)	111	5	119	6
Camas Power Boiler LP, unsecured term loan, due June 2007	(1)	L+2(2)	4	—	6	—
Camas Power Boiler LP, revenue bonds, due August 2007	3.38	L+2(2)	3	—	4	—
Itiquira Energetica S.A., due December 2013	12.00	—	30	—	31	—
Itiquira Energetica S.A., due January 2012	(1)	—	19	—	20	—
Capital leases:						
Saale Energie GmbH, Schkopau capital lease, due 2021	(1)	—	214	—	304	—
Subtotal			2,740	(58)	3,523	(39)
Less current maturities			108	(7)	508	3
Total			$ 2,632	$ (51)	$ 3,015	$ (42)

(1) Distinguishes debt with various interest rates.

(2) L+ equals LIBOR plus x%

(3) Fair value adjustment as of December 31, 2004 and December 31, 2005 reflects $16 million reduction and $20 million reduction, respectively, for an interest rate swap. In addition, the balances as of December 31, 2004 and December 31, 2005 reflect unamortized bond premium of $26 million and $14 million, respectively.

(4) $645 million in bonds have been redeemed or repurchased and retired in 2005.

As a result of adopting Fresh Start on December 6, 2003, the fair value of long-term debt was calculated using the indicated effective interest rates which approximate market rates. The fair value adjustments for these notes and capital leases are amortized into interest expense using the effective interest rate method. A fair value adjustment was not necessary for the senior notes and the credit facility as both of these obligations were entered into subsequent to Fresh Start. For those notes and capital leases where market pricing was not available, we used carrying amounts, which we believe approximated the market values as of December 6, 2003.

As of December 31, 2005, we have timely made scheduled payments on interest and/or principal on all of our recourse debt and were not in default under any of our related recourse debt instruments. Additionally, we are not in default on any obligations to post collateral.

Senior Securities

On December 23, 2003, we issued $1.25 billion in 8% Second Priority Notes, due and payable on December 15, 2013. On January 28, 2004, we issued an additional $475.0 million in Second Priority Notes, under the same terms and indenture as our December 23, 2003 offering.

When we issued the Second Priority Senior Secured Notes in December 2003, we entered into a Registration Rights Agreement with the purchasers of the Notes. Under the Registration Rights Agreement, we were required to file a Registration Statement with the SEC by May 21, 2004 (150 days after the issuance of the Notes) to permit the bonds to be publicly traded. When we did not meet this deadline, we were required to accrue liquidated damages, starting May 22, 2004 until the exchange was executed, which happened on June 14, 2005. In 2005, we made payments for liquidated damages totaling approximately $7 million. Accrued but unpaid liquidated damages were $0 and approximately $1 million as of December 31, 2005 and 2004, respectively.

During the first quarter of 2005, we used existing cash to purchase, at market prices, approximately $41 million in face value of our Second Priority Notes. These notes were subsequently retired. On February 4, 2005, we redeemed $375 million in Second Priority Notes. At the same time, we paid $30 million for the early redemption premium, approximately $4 million in accrued but unpaid interest and $0.4 million in accrued but unpaid liquidated damages on the redeemed notes. On September 12, 2005, we redeemed approximately $229 million in Second Priority Notes and paid approximately $18 million for the early redemption premium and $4 million in accrued but unpaid interest.

On December 15, 2005, we commenced a tender offer for all the outstanding Second Priority Notes. On December 30, 2005 we amended the indenture relating to the Second Priority Notes to remove many covenant restrictions, including the incurrence of additional indebtedness, having received the necessary consents from holders of the Second Priority Notes. Those holders who validly tendered their Second Priority Notes by February 2, 2006 were eligible to receive the tender offer consideration. On February 2, 2006 we closed our offer to purchase all outstanding Second Priority Notes. All but approximately $0.4 million aggregate principal amount of Second Priority Notes were tendered in such offer. The same day, we effected a covenant defeasance of our remaining Second Priority Notes by placing approximately $0.5 million in escrow with the trustee of the Second Priority Notes for payment in full on amounts due with respect to the non-tendered notes through the earliest redemption date, December 15, 2008. As a result of the defeasement, liens held by the remaining holders were released and all covenant obligations under these notes were extinguished; however, the subsidiary guarantees supporting our obligations under the Second Priority Notes remain.

The Second Priority Notes were refinanced on February 2, 2006 with new Senior Unsecured Notes which are described in Note 34 — Subsequent Events. As of December 31, 2005 and March 3, 2006, we had $1.08 billion and $0 in Second Priority Notes outstanding, respectively.

The Second Priority Notes were general obligations of ours. They were secured on a second-priority basis by security interests in all assets of ours, with certain exceptions, subject to the liens securing our obligations under the Amended Credit Agreement (described below) and any other priority lien debt. The notes were effectively subordinated to our obligations under the Amended Credit Facility and any other priority lien obligation. The Second Priority Notes were senior in right of payment to any future subordinated indebtedness. Interest on the Second Priority Notes accrued at the rate of 8.0% per annum and was payable semi-annually in arrears on June 15 and December 15, commencing on June 15, 2004. Accrued but unpaid interest was approximately $4 million and $6 million as of December 31, 2005 and 2004, respectively.

As of December 31, 2005, we had an interest rate swap in place to exchange fixed-rate interest payments for floating-rate interest payments. This swap agreement became effective March 26, 2004 and terminates December 15, 2013. The swap agreement has provisions for early termination that are linked to any prepayment of the Second Priority Notes. As of February 25, 2006, this swap agreement remains outstanding. Under the agreement, we agree to pay semi-annually in arrears, commencing June 15, 2004, a floating interest rate on a notional amount of $400 million, and receive semi-annually in arrears a fixed interest rate payment on the same notional amount. The floating interest rate is based upon six-month LIBOR plus a spread. Depending on market interest rates, we or the swap counter-party may be required to post collateral on a daily basis in support of this swap, to the benefit of the other party. On December 31, 2005 and as of March 3, 2006, we had approximately $5 million and $13 million in collateral posted.

On December 23, 2003 we and PMI entered into a Credit Facility for up to $1.45 billion with Credit Suisse, as Administrative Agent, Lehman Commercial Paper, Inc., as Syndication Agent and a group of lenders. The Credit Facility was amended on December 24, 2004 to consist of a $450 million senior secured term loan facility maturing December 24, 2011, a $350 million funded letter of credit facility maturing December 24, 2011, and a revolving credit facility in an amount up to $150 million, maturing December 24, 2007 (the "Amended Credit Facility"). The Amended Credit Facility was further amended on August 5 and December 27, 2005 to remove certain covenants restricting the incurrence and repayment of indebtedness. The balance outstanding under this facility was approximately $796 million as of December 31, 2005. Other expenses include commitment fees on the undrawn portion of the revolving credit facility, participation fees for the credit-linked deposit and other fees.

As of December 31, 2005, the $350 million letter of credit facility was fully funded and reflected as a funded letter of credit on the December 31, 2005 balance sheet. As of December 31, 2005, approximately $312 million in letters of credit had been issued under this facility, leaving approximately $38 million available for future issuances. Most of these letters of credit are issued in support of our obligations to perform under commodity agreements, financing or other arrangements. These letters of credit expire within one year of issuance, and it is not unusual for us to renew many of them on similar terms.

On September 22 and 23, 2005, we borrowed $80 million and $40 million, respectively, under our revolving credit facility to support working capital obligations. These borrowings were repaid on September 26 and October 26, 2005. As of December 31, 2005, we had no borrowings outstanding under the revolving credit facility.

On January 31, 2006, we repaid the outstanding principal balance of approximately $446 million, along with accrued but unpaid interest of approximately $2 million, under the term loan facility and terminated that facility. On February 2, 2006, we paid accrued but unpaid fees on our revolving credit facility and our funded letter of credit facility, and terminated those facilities. The facilities were replaced by new financing arrangements as of February 2, 2006. An interim arrangement has been made with Credit Suisse, such that letters of credit issued under the Amended Credit Facility will be retained at Credit Suisse until they are transferred to the letter of credit facility under the New Credit Agreement. In lieu of credit-linked deposits, we have issued to the benefit of Credit Suisse a letter of credit under our new funded letter of credit facility. The new credit facilities are described in Note 34 — Subsequent Events.

The Amended Credit Facility was secured by, among other things, first-priority perfected security interests in all of the property and assets owned at any time or acquired by us and our subsidiaries, other than the property and assets of certain excluded project subsidiaries, foreign subsidiaries and certain other subsidiaries, with some exceptions. The Amended Credit Facility bore interest at an interest rate of 1.875% over LIBOR, which was 4.39% as of December 31, 2005. As of December 31, 2005, we had an interest rate swap in place to hedge against fluctuations in floating interest rates. The swap agreement became effective March 26, 2004 and terminates March 31, 2006. Under the agreement, we agree to pay quarterly a fixed-rate interest payment on a notional amount of $400 million, commencing on March 31, 2004, and receive quarterly a floating-rate interest rate payment on the same notional amount. The floating rate is based upon three-month LIBOR, subject to a floor.

On December 5, 2003, we entered into a $10 million promissory note with Xcel Energy. The note accrues interest at a rate of 3% per year, payable quarterly in arrears. All principal is due at maturity on June 5, 2006.

See Note 34 — Subsequent Events for information related to recent financing activities related to the acquisition of Texas Genco.

Financing commitments — As discussed in Note 34, we financed the Acquisition through a combination of a senior secured credit facility, unsecured high yield notes and the sale of common and preferred equity securities in the public markets. As of December 31, 2005 we had received a commitment letter from Morgan Stanley Senior Funding, Inc., or Morgan Stanley, and Citigroup Global Markets, Inc., or Citigroup, to provide us with up to $4.8 billion in senior secured debt financing, including up to $3.2 billion under a senior first priority term loan facility, up to $600 million under a senior first priority secured revolving credit facility and up to $1 billion under a senior first priority secured synthetic letter of credit facility. The commitment letter further provided for up to $5.1 billion in bridge financing to fund all necessary amounts not provided for under the senior secured debt financing. This commitment letter was necessary if for some reason any of the planned financings were unavailable at the time of the closing. The commitment letter was subject to customary conditions to consummation, including the absence of any event or circumstance that would have a material adverse effect on the business, assets, properties, liabilities, condition (financial or otherwise) or results of operations, taken as a whole, of Texas Genco, or Texas Genco and NRG combined, since June 30, 2005. During the fourth quarter of 2005 we paid a fee of approximately $45 million for this commitment and were amortizing it over the commitment period. However, as all the financings have been completed without utilizing this commitment letter, we have expensed the remaining amount subsequent to the completion of the financings and Acquisition, during February of 2006.

Project Financings

The following are descriptions of certain indebtedness of NRG's project subsidiaries that remain outstanding on December 31, 2005. The indebtedness described below is non-recourse to NRG, unless otherwise described.

Peakers

In June 2002, NRG Peaker Financing LLC, or Peakers, an indirect wholly-owned subsidiary, issued $325 million in floating rate bonds due June 2019. Peakers subsequently swapped such floating rate debt for fixed rate debt at an all-in cost of 6.67% per annum. Principal, interest, and swap payments are guaranteed by XL Capital Assurance, or XLCA, through a financial guaranty insurance policy. Such notes are also secured by, among other things, substantially all of the assets of and membership interests in Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Sterlington Power LLC, NRG Rockford LLC, NRG Rockford II LLC and NRG Rockford Equipment LLC (all subsidiaries of NRG). As of December 31, 2005, approximately $297 million in principal remained outstanding on these bonds. In January 2004, terms of the financing arrangement were restructured, at which time we issued approximately $36 million letter of credit, under our corporate funded letter of credit facility to the Peakers' Collateral Agent. The letter of credit may be drawn if the project is unable to meet principal or interest payments. There are no provisions requiring us to replenish the letter of credit if it is drawn.

Flinders

In February 2005, NRG Flinders amended its debt facility of approximately AUD 279 million (approximately US $219 million) in floating-rate debt. The amendment extended the maturity to February 2017, reduced borrowing costs and reserve requirements, reduced debt service coverage ratios, removed mandatory cash sharing arrangements, and made other minor modifications to terms and conditions. The facility includes an AUD 20 million (approximately US $15 million) working capital and performance bond facility, under which approximately AUD 12 million (approximately US $9 million) in performance bonds and letters of credit have been issued as of December 31, 2005. An interim arrangement to indemnify the Australia New Zealand Bank, or ANZ, of up to approximately AUD 16 million was terminated on May 17, 2005. NRG Flinders is required to maintain interest-rate hedging contracts on a rolling 5-year basis at a minimum level of 60% of principal outstanding. During the year, Flinders made approximately AUD 61 million optional prepayments, approximately AUD 18 million of mandatory repayments and AUD 61 million of re-borrowings. As of December 31, 2005, AUD 241 million (approximately US $177 million) was outstanding.

NRG Thermal

NRG Thermal LLC, or NRG Thermal, has two subsidiaries with outstanding long-term debt. Such indebtedness is secured principally by the subsidiaries' long-term assets and is guaranteed by NRG Thermal and "cross-collateralized" by NRG Thermal's ownership interests in all of its subsidiaries. In July 2002, NRG Energy Center Minneapolis LLC issued $55 million of 7.25% Series A notes due August 2017, of which approximately $48 million remained outstanding as of December 31, 2005; $20 million of 7.12% Series B notes due August 2017, of which approximately $17 million remained outstanding as of December 31, 2005; and in August 1993, NRG Energy Center Minneapolis LLC issued $84 million of 7.31% senior secured notes due June 2013, of which approximately $46 million remained outstanding as of December 31, 2005. NRG Energy Center San Francisco LLC has issued $360 thousand of 7.63% senior secured term notes due September 2008, of which approximately $0.1 million remained outstanding at December 31, 2005.

Camas

In November 1990, Clark County, Washington issued $15 million in aggregate principal amount of 7.2% fixed interest Series A tax-exempt bonds due August 15, 2007 to fund the construction of the Camas project. The bonds were re-marketed with a 4.65% interest rate in August 1997 and again at a 3.375% interest rate in August 2002. This facility, pursuant to the indenture, can no longer be re-marketed. As of December 31, 2005, approximately $3 million remains outstanding. In 1997, Camas also acquired approximately $20 million floating-rate bank loan from Fort James Corporation, maturing in June 2007. The principal outstanding on this facility was approximately $4 million as of December 31, 2005.

Itiquira Energetica S.A.

On July 15, 2004, Itiquira Energetica S. A., a majority-owned subsidiary of ours, executed a long-term financing arrangement with União de Bancos Brasilieros S.A., or Unibanco, for a 55 million Brazilian Reals term loan maturing in January 2012. The facility bears a floating interest rate and amortizes on a schedule that is indexed to certain foreign exchange rates. The principal obligation as of December 31, 2005 was approximately $19 million. Eletrobrãs owns preferred shares in Itiquira, which for U.S. GAAP purposes are reflected as debt. The preferred shares accrue cumulative dividends of 12% per year, payable only at such time Itiquira has sufficient retained profits or reserves. The balance at December 31, 2005 was approximately $30 million.

Capital Leases

Saale Energie GmbH

Saale Energie GmbH, or SEG, an NRG subsidiary, has a 41.9% participation in the Schkopau Power Plant, or Schkopau, through our interest in the Kraftwerke Schkopau GbR, KSGbR, partnership. Under the terms of a Use and Benefit fee Agreement, SEG and the other partner to the project, E.ON Kraftwerke GmbH, are required to fund debt service and certain other costs resulting from the construction and financing of Schkopau. The Use and Benefit Fee Agreement is treated as a capital lease under US GAAP. Calls for funds are made to the partners based on their participation interest as cash is needed. The KSGbR issued debt to fund Schkopau pursuant to multiple facilities totaling approximately €887 million (approximately US $1.2 billion). As of December 31, 2005, approximately €362 million (approximately US $428 million) remained outstanding at Schkopau. Interest on the individual loans accrues at fixed rates averaging 5.68% per annum, with maturities occurring between years 2006 and 2015. The lenders to the project rely almost exclusively on the creditworthiness of E.ON Kraftwerke GmbH. SEG remains liable to the lenders as a partner in KSGbR, but there is no recourse to NRG. As of December 31, 2005 the capital lease obligation at SEG was approximately $214 million.

Consolidated annual maturities and future minimum lease payments:

Annual maturities of long-term debt and capital leases for the years ending after December 31, 2005 are as follows:

	Total (In millions)
2006	$ 108
2007	82
2008	66
2009	65
2010	71
Thereafter	2,348
Total	$ 2,740

Future minimum lease payments for capital leases included above at December 31, 2005 are as follows:

	(In millions)
2006	$ 77
2007	48
2008	42
2009	33
2010	19
Thereafter	187
Total minimum obligations	406
Interest	192
Present value of minimum obligations	214
Current portion	61
Long-term obligations	$ 153

Note 18 — Capital Structure

Common Stock

In connection with the consummation of our reorganization, on December 5, 2003, all shares of our old common stock were canceled and 100 million shares of new common stock of NRG were distributed pursuant to such plan in accordance with Section 1145 of the bankruptcy code to the holders of certain classes of claims. We received no proceeds from such issuance. A certain number of shares of common stock were issued and placed in the Disputed Claims Reserve for distribution to holders of disputed claims as such claims are resolved or settled. . In the event our disputed claims reserve is inadequate, it is possible we would have to issue additional shares of our common stock to satisfy such pre-petition claims or contribute additional cash proceeds.

Our authorized common stock consists of 500 million shares of NRG common stock. Common stock shares issued as of December 31, 2005 and 2004 were 100,048,676 and 100,041,935, respectively at a par value of $1 million. Common stock shares outstanding as of December 31, 2005 and 2004 were 80,701,888 and 87,041,935, respectively. A total of 4,000,000 shares of our common stock are available for issuance under our long — term incentive plan.

Treasury Stock

As of December 31, 2005 and 2004, the NRG Energy common stock shares repurchased by the company were 19,346,788 and 13,000,000, respectively, at a cost of $664 million and $405 million, respectively.

Upon emergence from chapter 11, investment partnerships managed by MatlinPatterson LLC owned approximately 21.5 million (21.5%) of our common shares. In December 2004, we used existing cash to repurchase 13 million shares of common stock from MatlinPatterson at a purchase price of $31.16 per share plus transaction costs of $0.2 million. In addition to a reduction in total shares of common stock outstanding by 13 million, the share repurchase resulted in (i) the reduction of MatlinPatterson's share ownership of NRG Energy to less than 10% from the prior 21.5%, (ii) termination of MatlinPatterson's registration rights, and (iii) resignation from our Board of Directors of three directors affiliated with MatlinPatterson.

On August 11, 2005, we entered into an Accelerated Share Repurchase Agreement with CSFB, pursuant to which we repurchased $250 million of our common stock on that date that equaled a total of 6,346,788 shares, which were held in treasury. We funded the repurchase with cash on hand. On March 3, 2006, we paid to CSFB a cash purchase price adjustment of approximately $7 million based upon the weighted average value of NRG's common stock over a period of approximately six months, subject to a minimum price of 97% and a maximum price of 103% of the closing price per share on August 10, 2005, or $39.39.

On February 2, 2006, we delivered to the Sellers all of the shares of common stock held in treasury as part of the consideration for the Texas Genco Acquisition. Also see Note 34 Subsequent Events.

Preferred Stock

At December 31, 2005, our authorized amount of preferred stock is 10,000,000 shares. As of December 31, 2005, our preferred stock consists of two series, the 4% Convertible Perpetual Preferred Stock, or 4% Preferred Stock and the 3.625% Convertible Perpetual Preferred Stock, which is treated as Redeemable Preferred Stock, or 3.625% Preferred Stock.

4% Preferred Stock

As of December 31, 2005 and 2004, 420,000 shares of the 4% Preferred Stock were issued and outstanding at a liquidation value, net of issuance costs of $406 million. The 4% Preferred Stock has a liquidation preference of $1,000 per share of 4% Preferred Stock. Holders of the 4% Preferred Stock are entitled to receive, when declared by our Board of Directors, cash dividends at the rate of 4% per annum, payable quarterly in arrears on March 15, June 15, September 15 and December 15 of each year, commencing on March 15, 2005. The 4% Preferred Stock is convertible, at the option of the holder, at any time into shares of our common stock at an initial conversion price of $40.00 per share, which is equal to a conversion rate of 25 shares of common stock per share of the 4% Preferred Stock, subject to specified adjustments. On or after December 20, 2009, we may redeem, subject to certain limitations, some or all of the 4% Preferred Stock with cash at a redemption price equal to 100% of the liquidation preference, plus accumulated but unpaid dividends, including liquidated damages, if any, to the redemption date.

If we are subject to a fundamental change, as defined in the Certificate of Designation of the 4% Convertible Perpetual Preferred Stock, each holder of shares of the 4% Preferred Stock has the right, subject to certain limitations, to require us to purchase any or all of its shares of Preferred Stock at a purchase price equal to 100% of the liquidation preference, plus accumulated and unpaid dividends, including liquidated damages, if any, to the date of purchase. Final determination of a fundamental change must be approved by the Board of Directors.

Each holder of the 4% Preferred Stock has one vote for each share of the 4% Preferred Stock held by the holder on all matters voted upon by the holders of our common stock, as well as voting rights specifically provided for in our amended and restated certificate of incorporation or as otherwise from time to time required by law. In addition, whenever (1) dividends on the 4% Preferred Stock or any other class or series of stock ranking on a parity with the 4% Preferred Stock with respect to the payment of dividends are in arrears for dividend periods, whether or not consecutive, containing in the aggregate a number of days equivalent to six calendar quarters, or (2) we fail to pay the redemption price on the date shares of the 4% Preferred Stock are called for redemption or the purchase price on the purchase date for shares of the 4% Preferred Stock following a fundamental change, then, in each case, the holders of the 4% Preferred Stock (voting separately as a class with all other series of preferred stock upon which like voting rights have been conferred and are exercisable) are entitled to vote for the election of two of the authorized number of our directors at the next annual meeting of stockholders and at each subsequent meeting until all dividends accumulated or the redemption price on the Preferred Stock have been fully paid or set apart for payment. The term of office of all directors elected by holders of the Preferred Stock terminates immediately upon the termination of the rights of the holders of the 4% Preferred Stock to vote for directors. Upon election of any additional directors, the number of directors that comprise our Board of Directors will be increased by the number of such additional directors.

The 4% Preferred Stock is, with respect to dividend rights and rights upon liquidation, winding up or dissolution: junior to all of our existing and future debt obligations; junior to each other class or series of our capital stock other than (1) our common stock and any other class or series of our capital stock which provides that such class or series will rank junior to the 4% Preferred Stock and (2) any other class or series of our capital stock the terms of which provide that such class or series will rank on a parity with the 4% Preferred Stock; on a parity with any other class or series of our capital stock the terms of which provide that such class or series will rank on parity with the 4% Preferred Stock; senior to our common stock and any other class or series of our capital stock the terms of which provide that such class or series will rank junior to the 4% Preferred Stock; and effectively junior to all of our subsidiaries (1) existing and future liabilities and (2) capital stock held by others.

The proceeds of $406 million net of issuance costs of approximately $14 million were primarily used to redeem $375 million of Second Priority Notes on February 4, 2005.

During the year ended December 31, 2005, we made $17 million of dividend payments to our 4% Preferred Stock shareholders.

Redeemable Preferred Stock

On August 11, 2005, we issued 250,000 shares of 3.625% Preferred Stock, which is treated as Redeemable Preferred Stock, to Credit Suisse First Boston Capital LLC, or CSFB, in a private placement. As of December 31, 2005, 250,000 shares of the 3.625% Preferred Stock were issued and outstanding at a liquidation value, net of issuance costs of $246 million. The 3.625% Preferred Stock is recorded based on the proceeds of $250 million net of issuance costs of $4 million. This amount will be accreted over a 10 year period to the redemption value of $250 million. The 3.625% Preferred Stock amount is located after the Liabilities but before the Stockholders' Equity section on the Balance Sheet as of December 31, 2005, due to the fact that the preferred shares can be redeemed in cash by the shareholder.

The 3.625% Preferred Stock has a liquidation preference of $1,000 per share. Holders of the 3.625% Preferred Stock are entitled to receive, out of funds legally available, cash dividends at the rate of 3.625% per annum, payable in cash quarterly in arrears commencing on December 15, 2005. Each share of 3.625% Preferred Stock is convertible during the 90-day period beginning August 11, 2015 at the option of NRG or the holder. Holders tendering the 3.625% Preferred Stock for conversion shall be entitled to receive, for each share of 3.625% Preferred Stock converted, $1,000 in cash and a number of shares of Common Stock equal to the product of (x) the greater of (i) the difference between the average of the closing sale price of the Common Stock on each of the 20 consecutive scheduled trading days starting on the date 30 scheduled exchange business days immediately prior to the conversion date, or the Market Price, and $59.085 and (ii) zero, times (y) 25.38715. The number of Common Stock shares to be delivered under the conversion feature is limited to 8,000,000 shares. If upon conversion, the Market Price is less than $39.39, then the Holder will deliver to NRG cash or a number of shares of Common Stock equal in value to the product of (A) $39.39 minus the Market Price, times (B) 25.38715. We may elect to make a cash payment in lieu of delivering shares of common stock in connection with such conversion, and we may elect to receive cash in lieu of shares of common stock, if any, from the Holder in connection with such conversion. If a fundamental change occurs, the holders will have the right to require us to repurchase all or a portion of the 3.625% Preferred Stock for a period of time after the fundamental change at a purchase price equal to 100% of the liquidation preference, plus accumulated and unpaid dividends. The 3.625% Preferred Stock are senior to all classes of common stock, on a parity with our 4% Preferred Stock and junior to all of our existing and future debt obligations and all of our subsidiaries' existing and future liabilities and capital stock held by persons other than NRG or our subsidiaries. The proceeds from issuing the 3.625% Preferred Stock were used to redeem $229 million of Second Priority Notes on September 12, 2005. During the year ended December 31, 2005, we made $3 million of dividend payments to our 3.625% Preferred Stock shareholders. See Note 34 — Subsequent Events for information related to recent equity transactions related to the acquisition of Texas Genco.

Note 19 — Stock-Based Compensation

Incentive Compensation Plans

Effective January 1, 2003, we adopted the fair value recognition provisions of SFAS 123. In accordance with SFAS 148, we adopted SFAS 123 under the prospective transition method which requires the application of the recognition provisions to all employee awards granted, modified, or settled after the beginning of the fiscal year in which the recognition provisions are first applied. In December 2004, the FASB issued a revision to SFAS 123, or SFAS 123(R) which requires us to recognize expense for stock — based compensation in the statement of income and is effective for us on January 1, 2006. We do not expect the provisions of SFAS 123(R) to result in a significant change in the compensation expense we currently recognize in our statements of income under SFAS 123.

During 2005, 2004 and 2003, in accordance with SFAS 123, we recognized approximately $12 million, $14 million and $0, respectively, of stock based compensation expense under the Long-Term Incentive Plan (as described below) as follows:

	2005	2004	2003
		(In millions)	
Non qualified stock options	$ 4	$ 7	$ —
Restricted stock units	7	5	—
Deferred stock units	1	2	—
Performance units	—	—	—
Total	$ 12	$ 14	$ —

In December 2003, we adopted a new long-term incentive plan, or the Long-Term Incentive Plan, which is described below.

Long-Term Incentive Plan

The Long-Term Incentive Plan became effective upon our emergence from bankruptcy and was also approved by our stockholders on August 4, 2004. The Long-Term Incentive Plan provides for grants of non-qualified stock options, restricted stock units, performance units, deferred stock units, stock appreciation rights and dividend equivalent rights, collectively referred to as Awards. Our directors, officers and employees, as well as other individuals performing services for, or to whom an offer of employment has been extended by us, are eligible to receive grants under the Long-Term Incentive Plan. The purpose of the Long-Term Incentive Plan is to promote our long-term growth and profitability by providing these individuals with incentives to maximize stockholder value and otherwise contribute to our success and to enable us to attract, retain and reward the best available persons for positions of responsibility.

A total of 4,000,000 shares of our common stock are available for issuance under the Long-Term Incentive Plan, subject to adjustment in the event of a reorganization, recapitalization, stock split, reverse stock split, stock dividend, and combination of shares, merger or similar change in our structure or our outstanding shares of common stock. There were 1,355,193 and 2,053,294 shares of common stock remaining available for grants of Awards under our Long-Term Incentive Plan as of December 31, 2005 and 2004, respectively.

The Compensation Committee of our Board of Directors administers the Long-Term Incentive Plan. If for any reason a Compensation Committee has not been appointed by our board to administer the Long-Term Incentive Plan, our Board of Directors has the authority to administer the plan and to take all actions under the plan.

The following is a summary of the material terms of the Long-Term Incentive Plan related to the Awards outstanding as of December 31, 2005. Unless otherwise noted, these terms are applicable to all Awards:

Eligibility. Our directors, officers and employees, as well as other individuals performing services for us are eligible to receive grants under the Long-Term Incentive Plan.

Exercise price and payment — The Compensation Committee determines the exercise price of any Award granted, typically the fair market value of a share of our common stock on the date of grant. In general, the exercise price of any NQSO may be paid by the holder, in any of the following ways:

- in cash;
- by delivery of shares of common stock with a fair market value equal to the exercise price;
- by means of any cashless exercise procedure approved by the Compensation Committee; or
- by any combination of the foregoing.

Term — The Compensation Committee determines the term of each Award, however, no term may exceed 10 years from the date of grant. In addition, all Awards generally cease vesting when a grantee ceases to be a director, officer or employee of, or to otherwise perform services for us. Vested Awards generally expire 90 days after the date of cessation of service. There are exceptions depending upon the circumstances such as the case of a grantee's death, termination due to disability and retirement, where the grantee's vested Awards remain exercisable for a period of one to two years

Change of control — Upon a change in control of NRG, all of the Awards become fully vested and remain exercisable until their expiration date. In addition, the Compensation Committee has the authority to grant Awards that become fully vested and exercisable automatically upon a change in control, whether or not the grantee is subsequently terminated.

Vesting, Withholding Taxes and Transferability of All Awards —

- Awards will vest over a period of not less than six months of the date of grant.
- Participants may elect to deliver shares of common stock, or to have us withhold shares of common stock deliverable upon vesting or exercise, in order to satisfy our tax withholding obligations.
- Awards are not transferable other than by will or the laws of descent and distribution.
- Awards may be exercised only by the grantee or his or her executor, administrator, guardian or legal representative, or by a family member of the grantee if he or she has acquired the award by gift or qualified domestic relations order.

Amendment and Termination of the Long-Term Incentive Plan. The Board of Directors or the Compensation Committee may amend or terminate the Long-Term Incentive Plan in its discretion, except that no amendment is effective without prior approval of our stockholders if approval is required by applicable law or regulations, including any NASDAQ or stock exchange listing requirements, if the amendment would remove a provision of the Long-Term Incentive Plan which, without giving effect to the amendment, is subject to shareholder approval or if the amendment would directly or indirectly increase the share limit of 4,000,000 shares. If not otherwise terminated, the Long-Term Incentive Plan terminates on the tenth anniversary of the effective date of our plan of reorganization, which was December 5, 2003.

The following types of Awards are issued and outstanding as of December 31, 2005:

Stock Options. The Compensation Committee may award grants of non-qualified stock options conforming to the requirements of Section 422 of the Internal Revenue Code, or NQSO's. The Compensation Committee may not award to any one person in any calendar year NQSO's to purchase more than 1,000,000 shares of common stock. In addition, it may not award NQSO's first exercisable in any calendar year whose underlying shares have a fair market value greater than $100,000, determined at the time of grant.

Restricted Stock Units. The Compensation Committee may award restricted stock units, or RSU's, in the amounts that it determines in its discretion. Each grant of RSU's is evidenced by a grant agreement, which specifies the applicable restrictions on such shares and the duration of the restrictions (which is generally at least six months). A grantee is required to pay us at least the aggregate par value of any shares of RSU's within ten days of the grant, unless the shares are treasury shares.

Performance Units. The Compensation Committee may grant performance units, or PU's, contingent upon achievement by the grantee, us or any of our divisions of specified performance criteria, such as return on equity over a specified performance cycle, fair market value of common stock at a specified target date, or other criteria as determined by the Compensation Committee. A performance award may be paid out in cash, shares of our common stock or our other securities.

Deferred Stock Units. The Compensation Committee may grant deferred stock units, or DSU's, from time to time in its discretion. A DSU entitles the grantee to receive the fair market value of one share of common stock at the end of the deferral period, which is no less than one year. The payment of the value of DSU's may be made by us in shares of our common stock, cash or both.

Stock Options

In 2005, we issued NQSO's for a total of 134,000 shares of common stock under the Long-Term Incentive Plan. These NQSO's have a three-year graded vesting schedule and become exercisable through the year 2008 at an exercise price of $38.80 and an estimated fair value of $13.22. During 2005, 1,500 NQSO's with an exercise price of $38.80 and an estimated fair value of $13.22 were canceled. Total compensation expense under all NQSO's grants is approximately $13 million. Compensation expense for the years ended December 31, 2005 and 2004 was approximately $4 million and $7 million, respectively. Compensation expense for the year ended December 31, 2006, will be approximately $2 million. Compensation expense for the years 2007 and 2008 is expected to be immaterial. At December 31, 2005, 531,834 employee NQSO's were exercisable. The following table summarizes NQSO transactions:

	Shares	Exercise Price Range per Share	Weighted-Average Exercise Price
Outstanding at December 6 and December 31, 2003	632,751	$ 24.03	$ 24.03
Granted	330,000	$ 19.90 - $31.48	$ 21.46
Outstanding at December 31, 2004	962,751	$ 19.90 - $31.48	$ 23.15
Granted	134,000	$ 38.80	$ 38.80
Canceled or expired	(1,500)	$ 38.80	$ 38.80
Outstanding at December 31, 2005	1,095,251	$ 19.90-38.80	$ 25.04

The following table summarizes information about stock options outstanding at December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of exercise prices	Total Outstanding	Weighted-Average Remaining Life (In Years)	Weighted-Average Exercise Price	Total Exercisable	Weighted-Average Exercise Price
$19.90 - $22.24	307,000	3.2	$ 20.92	102,333	$ 20.92
$24.03 - $31.48	655,751	7.9	$ 24.20	429,501	$ 24.11
$38.80	132,500	4.6	$ 38.80	—	—

The fair value of the stock option grants were estimated on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	2005	2004	2003
Dividends per year	—	—	—
Expected volatility	29.75%	51.05%	35.70%
Risk-free interest rate	4.16%	3.06%	4.24%
Expected life (years)	5	5	10
Fair value	$ 13.22	$ 10.20	$ 13.17

Restricted Stock Units

As of December 31, 2005, RSU's issued and outstanding totaled 1,285,944. These units fully vest between three and five years from the date of issuance. Total compensation expense attributable to the RSU's is approximately $35 million. During the year ended December 31, 2005, we issued 473,850 RSU's at fair values between $33.43 and $38.80 per unit, cancelled 66,250 RSU's at fair values between $19.90 and $38.80 per unit and issued 1,642 shares of common stock, net of common stock withheld for payroll taxes, due to accelerated vesting on 2,650 RSU's. Compensation expense for the years ended December 31, 2005 and 2004 was approximately $7 million and $5 million, respectively. Compensation expense for the years ended December 31, 2006, December 31, 2007, and December 31, 2008 will be approximately $12 million, $7 million and $3 million, respectively. The fair value of the RSU's is based on the closing price of our common stock on the date of grant. The weighted-average fair value of our RSU's outstanding as of December 31, 2005 is $27.14.

Deferred Stock Units

As of December 31, 2005, DSU's issued and outstanding totaled 122,184. During 2005, we issued 68,201 DSU's. The fair values of the DSU's issued during 2005 were between $34.72 and $41.05 per unit. These units are fully vested at the date of issuance. During the year ended December 31, 2005, we issued 5,099 shares of common stock, net of common stock withheld for payroll taxes, due to the conversion of 6,298 DSU's at fair values between $19.95 and $37.85 per unit. Total compensation expense attributable to the DSU grants is approximately $3 million. Compensation expense for the years ended December 31, 2005 and 2004 was approximately $1 million and $2 million, respectively. The fair value of the DSU's is based on the closing price of our common stock on the date of grant. The weighted-average fair value of our DSU's outstanding as of December 31, 2005 is $29.21

The reconciliation of basic earnings per common share to diluted earnings per share is shown in the following table:

	Reorganized NRG		
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003
	(In millions, except per share data)		
Basic earnings per share			
Numerator:			
Income from continuing operations	$ 77	$ 161	$ 11
Deduct preferred stock dividends	(20)	(1)	—
Net income available to common stockholders from continuing operations	57	160	11
Discontinued operations, net of tax	7	25	—
Net income available to common stockholders	$ 64	$ 185	$ 11
Denominator:			
Weighted average number of common shares outstanding	84.6	99.6	100.0
Basic earnings per share:			
Income from continuing operations	$ 0.67	$ 1.61	$ 0.11
Discontinued operations, net of tax	0.09	0.25	—
Net income	$ 0.76	$ 1.86	$ 0.11
Diluted earnings per share			
Numerator			
Net income available to common stockholders from continuing operations	$ 57	$ 160	$ 11
Add preferred stock dividends for dilutive preferred stock	—	1	—
Adjusted income from continuing operations	57	161	11
Discontinued operations, net of tax	7	25	—
Net income available to common stockholders	$ 64	$ 186	$ 11
Denominator:			
Weighted average number of common shares outstanding	84.6	99.6	100.0
Incremental shares attributable to the issuance of non-qualifying stock options (treasury stock method)	0.2	—	—
Incremental shares attributable to the issuance of non-vested restricted stock units (treasury stock method)	0.4	0.4	0.1
Incremental shares attributable to the assumed conversion of deferred stock units (if converted method)	0.1	0.1	—
Incremental shares attributable to the assumed conversion of the 4% preferred stock (if converted method)	—	0.3	—
Total dilutive shares	85.3	100.4	100.1
Diluted earnings per share:			
Income from continuing operations	$ 0.66	$ 1.60	$ 0.11
Discontinued operations, net of tax	0.09	0.25	—
Net income	$ 0.75	$ 1.85	$ 0.11

Anti-dilutive effect of certain equity instruments

Non-Qualified Stock Options — For the years ended December 31, 2005 and, 2004 and the period December 6, 2003 to December 31, 2003, options to purchase 132,500, 962,751 and 632,751 shares of common stock at an average price of $38.80, $23.15 and $24.03 per share, respectively, were not included in the earnings per share computation because the effect would be anti-dilutive.

Restricted Stock Units — For the years ended December 31, 2005 and 2004 , restricted stock units totaling 459,200 and 77,500 shares of common stock at an average price of $38.77 and $28.14 per share, respectively, were not included in the computation because the effect would be anti-dilutive. All the restricted stock units for the period December 6, 2003 to December 31, 2003 were included in the computation because the effect would be dilutive.

Performance Units — For the year ended December 31, 2005, 44,900 Performance Units which convert into common shares of stock were not included in the earnings per share computation as their effect would be anti-dilutive. There were no outstanding Performance Units as of December 31, 2004.

4% Preferred Stock — For the year ended December 31, 2005, the outstanding 4% Preferred Stock which are convertible into 10,500,000 shares of common stock were not included in the earnings per share computation because the effect would be anti-dilutive. However, for the year ended December 31, 2004, on a weighted average basis, 343,324 shares of common stock associated with the 4% Preferred Stock were included in the earnings per share computation.

3.625% Preferred Stock — The conversion feature of the 3.625% Preferred Stock, for the year ended December 31, 2005, is anti-dilutive and thus not included in the earnings per share computation. The conversion feature allows additional cash or common shares to be issued if the closing average stock price for a 20-day period prior to conversion exceeds the $59.08 market price trigger at conversion. The market price trigger was not reached as of December 31, 2005, and consequently, the conversion feature of the 3.625% Preferred Stock is considered anti-dilutive.

Note 21 — Segment Reporting

Our identified reportable segments are primarily based on geographic areas, both domestically and abroad. In connection with our emergence from bankruptcy and the new management team, we determined that it was necessary to adjust our segment reporting disclosures to more closely align our disclosures with the realignment of our management team. Accordingly, we have expanded our domestic geographical disclosures and collapsed our international geographical disclosures related to our wholesale power generation segment. In addition, our other segments have been further refined. As a result of these changes, we have retroactively recast our prior period disclosures in a consistent manner.

Beginning January 1, 2005 management changed the allocation criteria of corporate general and administrative expenses to the segments. Prior to 2005, corporate general and administrative expenses were allocated based on an analysis of man hours spent on work for each segment. As of January 1, 2005, corporate general and administrative expenses are allocated based on the forecasted revenue to be generated by each segment. In the following table, we have included a reconciliation of the increase/ (decrease) in net income by segment for the year ended December 31, 2005, assuming the prior allocation criteria was still in effect.

We conduct the majority of our business within five reportable operating segments based on geographic regions. Certain operations consisting of other products and services are presented under the "All Other" category. Our reportable operating segments consist of Wholesale Power Generation — Northeast, Wholesale Power Generation — South Central, Wholesale Power Generation — Western, Wholesale Power Generation — Other North America and Wholesale Power Generation — Australia. These reportable segments are distinct components with separate operating results and management structures in place.

Included in the All Other category are our Wholesale Power Generation — Other International operations, our Alternative Energy operations, our Non-Generation operations (comprised primarily from our operating services, power marketing and thermal operations) and an Other component which includes our corporate charges (primarily interest expense) that have not been allocated to the reportable segments and the remainder of our operations which are not significant. We have presented this detail within the All Other category as we believe that this information is important to a full understanding of our business.

All material revenues and long-lived assets attributable to foreign countries are presented in Wholesale Power Generation — Australia and All Other — Wholesale Power Generation — Other International reportable segments. Furthermore, the segment information has been reclassified for all discontinued operations.

	Reorganized NRG Year Ended December 31, 2005									
	Wholesale Power Generation					All Other				
	Northeast	South Central	Western	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(In millions)									
Operations										
Operating revenues	$ 1,554	$ 552	$ 1	$ 15	$ 212	$ 163	$ 70	$ 158	$ (17)	$2,708
Operating expenses	1,262	471	6	30	192	122	60	124	(3)	2,264
Depreciation and amortization	74	61	1	7	27	4	5	11	4	194
Corporate relocation charges	—	—	—	—	—	—	—	—	6	6
Reorganization items	—	—	—	—	—	—	—	—	—	—
Restructuring and impairment charges	—	—	—	6	—	—	—	—	—	6
Operating income/(loss)	218	20	(6)	(28)	(7)	37	5	23	(24)	238
Minority interest in earnings of consolidated subsidiaries	—	—	—	—	—	—	—	—	—	—
Equity in earnings (losses) of unconsolidated affiliates	—	—	22	13	24	45	—	—	—	104
Write downs and losses on sales of equity method investments		—	(27)	(16)		12	—	—	—	(31)
Other income (expense), net	4	—	1	13	3	21	2	6	12	62
Refinancing expenses	—	—	—	—	10	—	—	—	(66)	(56)
Interest expense		(9)		(18)	(13)	(8)		(9)	(140)	(197)
Income/(loss) from continuing operations before income taxes	222	11	(10)	(36)	17	107	7	20	(218)	120
Income tax expense/(benefit)	—	—	—	4	2	18	4	4	11	43
Income/(loss) from continuing operations	222	11	(10)	(40)	15	89	3	16	(229)	77
Income/(loss) on discontinued operations, net of income taxes	—	—	—	1	—		6	—	—	7
Net income/(loss)	$ 222	$ 11	$ (10)	$ (39)	$ 15	$ 89	$ 9	$ 16	$(229)	$ 84
Balance Sheet										
Equity investments in affiliates	1	—	188	56	163	195		—	—	603
Capital expenditures	51	26	—	—	17	—	1	6	5	106
Total assets	$ 1,810	$ 1,075	$ 200	$ 599	$ 825	$ 679	$ 74	$ 1,446	$ 723	$7,431

If the Company continued using the previous year's allocation method for corporate general and administrative expenses, the effect to the net income of each segment for the year ended December 31, 2005 would be as follows:

	Northeast	South Central	Western	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
Net income/(loss) as reported	$ 222	$ 11	$ (10)	$ (39)	$ 15	$ 89	$ 9	$ 16	$(229)	$ 84
Increase/(decrease) in net income	25	13	—	(1)	6	4	1	5	(53)	—
Adjusted net income/(loss)	$ 247	$ 24	$ (10)	$ (40)	$ 21	$ 93	$ 10	$ 21	$(282)	$ 84

Reorganized NRG
Year Ended December 31, 2004

	Wholesale Power Generation					All Other				
	Northeast	South Central	Western	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(In millions)									
Operations										
Operating revenues	$ 1,251	$ 418	$ 3	$ 94	$ 181	$ 157	$ 65	$ 186	$ (7)	$2,348
Operating expenses	860	294	11	51	162	122	61	101	37	1,699
Depreciation and amortization	73	62	1	21	24	3	5	11	8	208
Corporate relocation charges	—	—	—	—	—	—	—	—	16	16
Reorganization items	—	1	—	—	—	—	—	1	(15)	(13)
Restructuring and impairment charges	—	3	—	27	—	—	—	—	15	45
Operating income/(loss)	318	58	(9)	(5)	(5)	32	(1)	73	(68)	393
Minority interest in earnings of consolidated subsidiaries	—	—	—	—	—	—	—	—	—	—
Equity in earnings (losses) of unconsolidated affiliates	—	—	74	16	18	51	1	—	—	160
Write downs and losses on sales of equity method investments	—	—	—	(11)	(1)	—	(4)	—	—	(16)
Other income (expense), net	5	—	—	3	4	7	1	2	5	27
Refinancing expenses	—	—	—	—	—	—	—	—	(72)	(72)
Interest expense	(1)	(9)	—	(45)	(11)	(11)	—	(8)	(181)	(266)
Income/(loss) from continuing operations before income taxes	322	49	65	(42)	5	79	(3)	67	(316)	226
Income tax expense/(benefit)	—	—	—	(10)	(5)	13	(1)	5	63	65
Income/(loss) from continuing operations	322	49	65	(32)	10	66	(2)	62	(379)	161
Income/(loss) on discontinued operations, net of income taxes	—	—	—	14	—	12	2	—	(3)	25
Net income/(loss)	$ 322	$ 49	$ 65	$ (18)	$ 10	$ 78	$ —	$ 62	$ (382)	$ 186
Balance Sheet										
Equity investments in affiliates	1	—	256	76	156	246	—	—	—	735
Capital expenditures	49	31	—	1	22	2	2	4	8	119
Total assets	$ 1,932	$ 1,077	$ 279	$ 783	$ 1,008	$ 939	$ 51	$ 512	$1,283	$7,864

	Reorganized NRG December 6, 2003 Through December 31, 2003									
	Wholesale Power Generation					All Other				
	Northeast	South Central	Western	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(In millions)									
Operations										
Operating revenues	$ 69	$ 27	$ —	$ 4	$ 12	$ 13	$ 4	$ 10	$ (2)	$ 137
Operating expenses	53	20	—	2	10	11	4	8	—	108
Depreciation and amortization	5	3	—	2	2	—	—	—	—	12
Reorganization items	—	—	—	—	—	—	—	—	2	2
Operating income/(loss)	11	4	—	—	—	2	—	2	(4)	15
Minority interest in earnings of consolidated subsidiaries	—	—	—	—	—	—	—	—	—	—
Equity in earnings of unconsolidated affiliates	—	—	10	2	1	1	—	—	—	14
Other income (expense), net	—	—	—	—	1	—	—	—	(1)	—
Interest expense	(3)	(4)	—	(3)	(1)	—	—	(1)	(7)	(19)
Income/(loss) from continuing operations before income taxes	8	—	10	(1)	1	3	—	1	(12)	10
Income tax expense/(benefit)	—	—	—	—	—	1	—	—	(2)	(1)
Income/(loss) from continuing operations	8	—	10	(1)	1	2	—	1	(10)	11
Income/(loss) on discontinued operations, net of income taxes	—	—	—	—	—	—	—	—	—	—
Net income/(loss)	$ 8	$ —	$ 10	$ (1)	$ 1	$ 2	$ —	$ 1	$ (10)	$ 11

	Wholesale Power Generation					All Other				
	Northeast	South Central	Western	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	Predecessor Company January 1, 2003 Through December 5, 2003 (In millions)									
Operations										
Operating revenues	$ 861	$ 357	$ 24	$ 86	$ 151	$ 137	$ 61	$ 129	$ (8)	$1,798
Operating expenses	800	247	7	45	124	111	52	87	51	1,524
Depreciation and amortization	90	34	11	29	17	4	5	12	9	211
Reorganization items	2	29	—	41	—	—	—	—	126	198
Restructuring and impairment charges	232	2	—	17	—	—	1	—	(15)	237
Fresh start reporting adjustments	1,068	429	107	415	78	(11)	50	181	(6,537)	(4,220)
Legal settlement	—	—	—	4	—	—	(9)	—	468	463
Operating income/(loss)	(1,331)	(384)	(101)	(465)	(68)	33	(38)	(151)	5,890	3,385
Equity in earnings of unconsolidated affiliates	—	—	103	7	30	32	(1)	—	—	171
Write downs and losses on sales of equity method investments	—	—	—	12	(146)	3	(16)	—	—	(147)
Other income (expense), net	3	1	—	2	(1)	13	2	—	(1)	19
Interest expense	(70)	(74)	—	(70)	(4)	(8)	—	(10)	(72)	(308)
Income/(loss) from continuing operations before income taxes	(1,398)	(457)	2	(514)	(189)	73	(53)	(161)	5,817	3,120
Income tax expense/(benefit)	—	—	36	5	15	17	2	—	(37)	38
Income/(loss) from continuing operations	(1,398)	(457)	(34)	(519)	(204)	56	(55)	(161)	5,854	3,082
Income/(loss) on discontinued operations, net of income taxes	—	—	—	(414)	—	138	(25)	—	(15)	(316)
Net income/(loss)	$ (1,398)	$ (457)	$ (34)	$ (933)	$ (204)	$ 194	$ (80)	$ (161)	$ 5,839	$2,766

Note 22 — Income Taxes

The income tax provision (benefit) from continuing operations consists of the following amounts:

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
Current				
U.S.	$ 19	$ —	$ (2)	$ 2
Foreign	16	17	1	16
	35	17	(1)	18
Deferred				
U.S.	2	57	—	3
Foreign	6	(9)	—	17
	8	48	—	20
Total income tax (benefit)	$ 43	$ 65	$ (1)	$ 38
Effective tax rate	35.8%	28.7%	(6.2)%	1.3%

The following represents the domestic and foreign income components of income (loss) from continuing operations before income tax expense (benefit):

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
U.S.	$ (4)	$ 138	$ 6	$ 3,236
Foreign	124	88	4	(116)
	$ 120	$ 226	$ 10	$ 3,120

A reconciliation of the U.S. federal statutory rate of 35% to our effective rate from continuing operations for the year ended December 31, 2005 and 2004 and the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003 is as follows:

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
Income/(Loss) From Continuing Operations Before Income Taxes	$ 120	$ 226	$ 10	$ 3,120
Tax at 35%	42	80	4	1,092
State taxes, (net of federal benefit)	(1)	6	(2)	265
Foreign operations	(21)	(22)	(1)	15
Section 965 Taxable Dividend	5	—	—	—
Subpart F Taxable Income	19	—	—	—
Fresh Start accounting adjustments	—	—	—	(1,440)
Valuation allowance	(22)	—	(1)	71
Change in state effective tax rate	22	—	—	—
Change in tax rate	—	—	—	36
Permanent differences, reserves, other	(1)	1	(1)	(1)
Income Tax Expense/(Benefit)	$ 43	$ 65	$ (1)	$ 38
Effective income tax rate	35.8%	28.7%	(6.2)%	1.3%

The temporary differences, which give rise to our deferred tax assets and liabilities consist of the following:

	Reorganized NRG	
	December 31, 2005	December 31, 2004
	(In millions)	
Deferred tax liabilities:		
Discount/premium on notes	$ 23	$ 20
Emissions credits	113	115
Difference between book and tax basis of property	247	246
Total deferred tax liabilities	383	381
Deferred tax assets:		
Deferred compensation, accrued vacation and other reserves	56	54
Development costs	2	3
Net unrealized gains on mark to market transactions	148	10
Foreign net operating loss carryforwards	46	64
Differences between book and tax basis of contracts	146	162
Non-depreciable Property	197	182
Intangibles amortization (other than goodwill)	12	13
Restructuring costs	80	60
U.S. net operating loss carry forwards	38	40
U.S. capital loss carryforwards	238	280
Investments in projects	63	83
Other	8	3
Total deferred tax assets (before valuation allowance)	1,034	954
Valuation allowance	(756)	(708)
Net deferred tax assets	278	246
Net deferred tax liability	$ 105	$ 135

The net deferred tax liability consists of:

	Reorganized NRG	
	December 31, 2005	December 31, 2004
	(In millions)	
Current deferred tax asset	$ (4)	$ —
Non-current deferred tax asset	(26)	(34)
Non-current deferred tax liability	135	169
Net deferred tax liability	$ 105	$ 135

The effective income tax rate for the year ended December 31, 2005 differs from the U.S. statutory rate of 35% due to the U.S. income inclusion upon the sale of Enfield (considered subpart F income), the taxable portion of a dividend from foreign operations repatriated pursuant to the American Jobs Creation Act of 2004, or the Jobs Act, and partially offset due to earnings in foreign jurisdictions taxed at rates lower than the U.S. statutory rate.

For the year ended December 31, 2005 we increased the estimated state effective income tax rate to 9% from the prior year state income tax rate of 7%. This increase is due to management's best estimate of the effective income tax rates for the various state and local taxing jurisdictions that we expect to be subject to for income tax filing purposes based on our business operations within each state. An increase to the net deferred tax asset balance of approximately $22 million has been recorded for which a corresponding valuation allowance as required has been established.

On February 2, 2006, we acquired Texas Genco for which we will obtain a step up in basis for a large portion of the newly acquired assets, which will generate tax depreciation expense deductions reducing our taxable income in future periods.

Taxes payable

During 2005, we recorded a current tax payable of approximately $22 million that represents a liability due to domestic federal and state tax of approximately $19 million as well as foreign taxes payable of approximately $3 million. During 2004, the Company generated current year domestic net operating losses for federal and state tax purposes, however we had a $5 million foreign current tax payable.

Deferred tax assets and valuation allowance

For U.S. income tax purposes, NRG generated additional net deferred tax assets of $80 million for the year ended December 31, 2005 of which a valuation allowance of $65 million was applied due to the uncertainty of utilization in future periods. As a result of our 2004 income tax filing, for financial reporting purposes we increased our domestic NOL's by $198 million and utilized $207 million during 2005. As of December 31, 2005 we have an outstanding domestic NOL carryforward of $93 million that will expire through 2025. Cumulative foreign NOL carryforwards of $156 million have no expiration date.

We believe that it is more likely than not that a benefit will not be realized on a substantial portion of our deferred tax assets. This assessment included consideration of positive and negative evidence, our current financial position and results of historical operations, current operations, projected future taxable income, projected operating and capital gains and our available tax planning strategies. During the year ended December 31, 2005, we reduced the domestic valuation allowance as a result of the utilization of tax assets and generated taxable income during the period. Positive evidence exists that current deferred tax assets when realized during 2006 can be carried back to offset taxable income in 2005. As a result, a corresponding decrease to the valuation allowance was recorded.

As of December 31, 2005, a consolidated valuation allowance of $756 million was recorded against the net deferred tax assets, of which $741 million is for domestic deferred tax assets and $15 million is for foreign deferred tax assets. Furthermore, the consolidated valuation allowance is comprised of a current and non-current portion of approximately $114 million and $642 million, respectively.

Under SOP 90-7, any future benefits from reducing a valuation allowance from pre-confirmation deferred tax assets should first reduce intangibles until exhausted and thereafter be reported as a direct addition to paid-in capital, versus a benefit on our income statement. Consequently, our effective tax rate in post-bankruptcy emergence years will not benefit from the realization of our deferred tax assets, which were fully valued as of the date of our emergence from bankruptcy. During 2005 we reduced our valuation allowance by $17 million with a corresponding reduction to our intangibles by the same amount. At December 31, 2005, approximately $674 million of pre-confirmation valuation allowance remained. Upon recognition in future periods, a reduction to this portion of the valuation allowance will be recorded against our intangible assets, and once exhausted, increase our paid-in capital.

Repatriation of foreign funds pursuant to the American Jobs Creation Act of 2004

Pursuant to the Jobs Act, NRG may elect to deduct 85% of certain eligible dividends received from non-U.S. subsidiaries from its taxable income before the end of 2005 if those dividends are reinvested in the U.S. for eligible purposes. During the year ended December 31, 2005, NRG repatriated approximately $298 million of accumulated foreign earnings. Only a portion of this amount represents the cumulative earnings and profits which will result in approximately $4.7 million of tax expense. The remaining amounts transferred are considered a return of capital. To the extent that NRG does not provide deferred income taxes for unremitted earnings, it is management's intent to permanently reinvest those earnings overseas in accordance with APB Opinion No. 23 *Accounting for Income Taxes-Special Areas*, or APB 23. As of December 31, 2005, there are no cumulative losses from our foreign subsidiaries.

Tax Holidays

During 2005, the "Amazon Development Agency" granted an income tax holiday to our subsidiary Itiquira Energetica SA pertaining to the local tax liability resulting from Itiquira's operating income for Brazilian tax purposes, applicable retroactively to January 1, 2005. The tax holiday program will reduce the effective income tax rate to 15.25% from a statutory income tax rate of 34% and will expire in December 31, 2013.

Note 23 — Related Party Transactions

Stock Purchase Agreement

Upon emergence from chapter 11, investment partnerships managed by MatlinPatterson LLC owned approximately 21.5 million (21.5%) of our common shares. We used existing cash to repurchase 13 million shares of common stock from MatlinPatterson pursuant to a stock purchase agreement dated December 13, 2004 at a purchase price of $31.16 per share. In addition to a reduction in total shares of common stock outstanding by 13 million, the share repurchase resulted in (i) the reduction of MatlinPatterson's share ownership of NRG Energy to less than 10% from the prior 21.5%, (ii) termination of MatlinPatterson's registration rights, and (iii) resignation from our Board of Directors of three directors affiliated with MatlinPatterson.

Operating Agreements

We entered into operation and maintenance agreements, or O&M agreements, with certain of our equity investments — WCP, Saguaro, Gladstone and MIBRAG. Fees for services under these contracts primarily include recovery of our costs of operating the plant as approved in the annual budget, as well as a base monthly fee. At WCP, we also provide services under Administrative Management Agreements, or AMAs. Services provided under the AMAs include environmental, engineering, legal and public relations services not covered under the O&M agreements. We also entered into long-term coal purchase agreements with MIBRAG to supply coal to Schkopau, a consolidated subsidiary. These fees and expenses are included in our operating revenues and operating costs in the consolidated statements of operations and consisted of the following:

Related Party Transactions with Equity Investments:

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
Revenues from Related Parties Included in Revenues from Majority-Owned Operations				
WCP				
O&M fees	$ 6	$ 4	$ —	$ 6
AMA fees	2	3	—	1
Saguaro				
O&M fees	—	—	—	—
Gladstone				
O&M fees	3	2	—	1
MIBRAG				
O&M fees	4	3	—	3
Total	$ 15	$ 12	$ —	$ 11
Expenses from Related Parties Included in Cost of Majority-Owned Operations				
MIBRAG				
Cost of purchased coal	$ 41	$ 39	$ 3	$ 36

Xcel Energy

Prior to our emergence from bankruptcy on December 5, 2003, NRG Energy was an indirect, wholly-owned subsidiary of Xcel Energy. Prior to December 5, 2003, we had entered into material transactions and agreements with Xcel Energy which are described below. Upon emergence from bankruptcy, we became an independent public company with no material affiliation or relationship to Xcel Energy. We have included amounts paid to or received from Xcel Energy during the year ended December 31, 2005, December 31, 2004 and for the period December 6, 2003 to December 31, 2003 only for comparative purposes, as these transactions are not considered related party transactions subsequent to December 5, 2003.

Operating Agreements

We have two agreements with Xcel Energy for the purchase of thermal energy. Under the terms of the agreements, Xcel Energy charges us for certain costs (fuel, labor, plant maintenance, and auxiliary power) incurred by Xcel Energy to produce the thermal energy. We paid Xcel Energy $11 million, $11 million, $1 million, and $10 million during the year ended December 31, 2005 and 2004, the period December 6, 2003 to December 31, 2003, and the period January 1, 2003 to December 5, 2003 respectively, under these agreements. These agreements are expected to terminate in 2007.

We have a renewable 10-year agreement with Xcel Energy, expiring on December 31, 2006, whereby Xcel Energy agreed to purchase refuse-derived fuel for use in certain of its boilers and we agree to pay Xcel Energy a burn incentive. Under this agreement, we received $2 million, $1 million, $0 and $1 million from Xcel Energy and paid $4 million, $4 million, $0 million and $4 million to Xcel Energy during the year ended December 31, 2005 and 2004, the period December 6, 2003 to December 31, 2003 and the period January 1, 2003 to December 5, 2003, respectively.

Administrative Services and Other Costs

We had an administrative services agreement in place with Xcel Energy. Under this agreement we reimbursed Xcel Energy for certain overhead and administrative costs, including benefits administration, engineering support, accounting and other shared services as requested by us. In addition, our employees participated in certain employee benefit plans of Xcel Energy as discussed in Note 24. We reimbursed Xcel Energy in the amount of $7.3 million during the period January 1, 2003 to December 5, 2003, under this agreement. This agreement was terminated December 5, 2003.

Natural Gas Marketing and Trading Agreement

We had an agreement with e prime, a wholly-owned subsidiary of Xcel Energy, under which e prime provided natural gas marketing and trading from time to time at our request. This agreement was terminated by e prime on December 12, 2002 and a termination charge of $0.3 million was paid in the period January 1, 2003 to December 5, 2003.

Note 24 — Benefit Plans and Other Postretirement Benefits

Reorganized NRG

Substantially all employees hired prior to December 5, 2003 were eligible to participate in our defined benefit pension plans. We have initiated new NRG Energy noncontributory, defined benefit pension plans effective January 1, 2004, with credit for service from December 5, 2003.

In addition, we provide postretirement health and welfare benefits (health care and death benefits) for certain groups of our employees. Generally, these are groups that were acquired in recent years and for whom prior benefits are being continued (at least for a certain period of time or as required by union contracts). Cost sharing provisions vary by acquisition group and terms of any applicable collective bargaining agreements. We expect to contribute approximately $18 million to our NRG pension plans in 2006.

NRG Flinders Retirement Plan

Employees of NRG Flinders, a wholly-owned subsidiary of NRG Energy, are members of the multiemployer Electricity Industry Superannuation Schemes, or EISS. Members of the EISS make contributions from their salary and the EISS Actuary makes an assessment of our liability. As a result of adopting Fresh Start we recorded a liability of approximately $14 million at December 5, 2003, to record our accumulated benefit obligation plan assets on the balance sheet at fair value. The balance sheet includes a liability related to the Flinders retirement plan of $15 million and $9 million at December 31, 2005 and 2004, respectively. NRG Flinders contributed approximately $6 million, $10 million, $0 and $5 million for the years ended December 31, 2005 and 2004, the period December 6 through December 31, 2003 and the period January 1 through December 5, 2003, respectively.

The Superannuation Board is responsible for the investment of EISS assets. The assets may be invested in government securities, shares, property and a variety of other securities and the Board may appoint professional investment managers to invest all or part of the assets on its behalf.

NRG Pension and Postretirement Medical Plans

Components of Net Periodic Benefit Cost

The net annual periodic pension cost related to our domestic plans, include the following components:

	Pension Benefits			
	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
Service cost benefits earned	$ 11	$ 11	$ 1	$ —
Interest cost on benefit obligation	4	3	—	—
Expected return on plan assets	—	—	—	—
Curtailment gain	—	(1)	—	—
Net periodic benefit cost	$ 15	$ 13	$ 1	$ —

	Other Benefits			
	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
Service cost benefits earned	$ 2	$ 1	$ —	$ 1
Interest cost on benefit obligation	3	3	—	2
Amortization of prior service cost	—	—	—	—
Recognized actuarial (gain)/loss	—	—	—	—
Net periodic benefit cost	$ 5	$ 4	$ —	$ 3

Reconciliation of Funded Status

A comparison of the pension benefit obligation and pension assets at December 31, 2005 and 2004 for all of our plans on a combined basis is as follows:

Reorganized NRG	Pension Benefits December 31, 2005	Pension Benefits December 31, 2004	Other Benefits December 31, 2005	Other Benefits December 31, 2004
	(In millions)			
Benefit obligation at January 1	$ 64	$ 49	$ 51	$ 42
Service cost	11	11	2	1
Interest cost	4	3	3	3
Plan initiation	—	—	—	—
Plan amendments	—	—	—	—
Plan curtailment		(1)	—	—
Actuarial (gain)/loss	5	2	2	6
Benefit payments	(1)	—	(1)	(1)
Benefit obligation at December 31	$ 83	$ 64	$ 57	$ 51
Fair value of plan assets at January 1	1	—	—	—
Actual return on plan assets	—	—	—	—
Employer contributions	13	1	1	1
Benefit payments	(1)	—	(1)	(1)
Fair value of plan assets at December 31	$ 13	$ 1	$ —	$ —
Funded status at December 31 — excess of obligation over assets	(70)	(63)	(57)	(51)
Unrecognized net (gain) loss	8	2	8	6
Accrued benefit liability recognized on the consolidated balance sheet at December 31	$ (62)	$ (61)	$ (49)	$ (45)

Amounts recognized in the balance sheets consist of:

	Pension Benefits December 31, 2005	Pension Benefits December 31, 2004	Other Benefits December 31, 2005	Other Benefits December 31, 2004
	(In millions)			
Accrued benefit cost	$ (62)	$ (61)	$ (49)	$ (45)
Unfunded accrued benefit obligation	—	—	—	—
Intangible assets	—	—	—	—
Accumulated other comprehensive income	—	—	—	—
Net amount recognized	$ (62)	$ (61)	$ (49)	$ (45)

The following table presents the balances of significant components of our domestic pension plans:

	Pension Benefits	
	December 31, 2005	December 31, 2004
	(In millions)	
Projected benefit obligation	$ 83	$ 64
Accumulated benefit obligation	35	16
Fair value of plan assets	13	1

The following table presents the significant assumptions used to calculate the benefit obligations:

	Pension Benefits		Other Benefits	
	2005	2004	2005	2004
Weighted-average assumptions used to determine benefit obligations at December 31				
Discount rate	5.50%	5.75%	5.50%	5.75%
Rate of compensation increase	4.00 - 4.50%	4.00 - 4.50%	—	—
Health care trend rate	—	—	11.5% grading to 5.5% in 2012	9% grading to 5.5% in 2009

The following table presents the significant assumptions used to calculate the benefit expense:

	Pension Benefits		Other Benefits	
	2005	2004	2005	2004
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31				
Discount rate	5.75%	6.00%	5.75%	6.00%
Expected return on plan assets	8.00%	8.00%	—	—
Rate of compensation increase	4.00 - 4.50%	4.00 - 4.50%	—	—
Health care trend rate	—	—	9% grading to 5.5% in 2009	10% grading to 5.5% in 2009

We use December 31 of each respective year as the measurement date for our pension and other benefit plans. We set the discount rate assumptions on an annual basis for each of our retirement related benefit plans at their respective measurement date. This rate is determined by our Investment Committee based on information provided by our actuary whose discount rate assumptions reflect the current rate at which the associated liabilities could be effectively settled at the end of the year. Such assumptions consider high-quality corporate bond indices, such as Moody's Aa, when selecting the discount rate. Using these methodologies, we determined a discount rate of 5.50% to be appropriate as of December 31, 2005, which is a reduction of 0.25% from the rate used as of December 31, 2004.

NRG employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The target allocation of plan assets is 60% to 80% invested in equity securities, with the remainder invested in fixed income securities. The Investment Committee will review the asset mix periodically and as the plan assets increase in future years, the Committee may examine other asset classes such as real estate, private equity, etc. NRG employs a building block approach to determining the long-term rate of return for plan assets with proper consideration given to diversification and rebalancing. Historical markets are studied and long-term historical relationships between equities and fixed income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. Peer data and historical returns are reviewed to check for reasonability and appropriateness.

Plan assets are currently invested in a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across US and non-US stocks, as well as growth, value, and small and large capitalizations. The plan assets weighted average allocation was as follows:

	December 31	
	2005	2004
US Equity	56%	N/A
International Equity	15%	N/A
US Fixed Income	29%	N/A
Cash	—	N/A

Expected future benefit payments are:

	Pension Benefits	Post Retirement Medical Plans	
	Benefit Payments	Benefit Payments	Medicare Prescription Drug Reimbursements
		(In millions)	
2006	$ 1	$ 1	$ —
2007	1	2	—
2008	3	2	—
2009	4	3	—
2010	6	3	—
2011-2015	50	18	1

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effect:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total service and interest cost components	$ 1	$ —
Effect on postretirement benefit obligation	6	(5)

Defined Contribution Plans

Our employees have also been eligible to participate in defined contribution 401(K) plans. Our contributions to these plans were approximately $5 million, $4 million and $4 million for the years ended December 31, 2005, 2004 and 2003, respectively.

Predecessor Company

Prior to December 5, 2003, all eligible employees participated in Xcel Energy's noncontributory, defined benefit pension plan, which was formerly sponsored by NSP. We sponsored two defined benefit plans that were merged into Xcel Energy's plan as of June 30, 2002. Benefits were generally based on a combination of an employee's years of service and earnings. Some formulas also took into account Social Security benefits. Plan assets principally consisted of the common stock of public companies, corporate bonds and U.S. government securities.

Prior to December 5, 2003, certain former NRG retirees were covered under the legacy Xcel Energy plan, which was terminated for non-bargaining employees retiring after 1998 and for bargaining employees retiring after 1999.

As a result of our emergence from bankruptcy on December 5, 2003, we are no longer owned by or affiliated with Xcel Energy and our employees are no longer active participants in the Xcel Energy plans.

Participation in Xcel Energy, Inc. Pension Plan and Postretirement Medical Plan

We did not make contributions to the Xcel Energy pension plan and postretirement plan in 2003. As of December 31, 2003, there are no liabilities recorded related to the Xcel Energy plans. The liabilities associated with these plans were settled as part of the NRG plan of reorganization. The net annual periodic cost (credit) related to our portion of the Xcel Energy pension plan and postretirement plans totaled $0.2 million 2003.

Prior to December 5, 2003, certain employees also participated in Xcel Energy's noncontributory defined benefit supplemental retirement income plan. This plan was for the benefit of certain qualifying executive personnel. Benefits for this unfunded plan were paid out of operating cash flows. The liability related to this plan was not material as of December 31, 2005 and 2004, respectively.

2003 Medicare Legislation

In May 2004, the FASB issued FSP 106-2 that provides guidance on accounting for the effects of the new Medicare Prescription Drug, Improvement, and Modernization Act of 2003 by employers whose prescription drug benefits are actuarially equivalent to the drug benefit under Medicare Part D. FSP 106-2 is effective as of the first interim period beginning after June 15, 2004. NRG Energy adopted FSP 106-2 in the third quarter of 2004 on a retroactive basis. Adoption of FSP 106-2 reduces the annual non-cash postretirement health expense by approximately $0.2 million and reduce the accumulated postretirement benefit obligation by $2.2 million. The change in accumulated postretirement benefit obligation has been reflected as an actuarial gain and will be amortized in future periods.

Note 25 — Commitments and Contingencies

Operating Lease Commitments

We lease certain of our facilities and equipment under operating leases, some of which include escalation clauses, expiring on various dates through 2023. Certain operating lease agreements over their lease term include provisions such as scheduled rent increases, leasehold incentives and rent concessions. We recognize the effects of those scheduled rent increases, leasehold incentives and rent concessions on a straight-line basis over the lease term unless another systematic and rational allocation basis is more representative of the time pattern in which the leased property is physically employed. Rental expense under these operating leases was approximately $9 million for the year ended December 31, 2005, $11 million for the year ended December 31, 2004, $1 million for the period December 6, 2003 through December 31, 2003 and $12 million for the period January 1, 2003 through December 5, 2003. Future minimum lease commitments under these leases for the years ending after December 31, 2005 are as follows:

	Total (In millions)
2006	$ 25
2007	21
2008	16
2009	14
2010	13
Thereafter	61
Total	$ 150

In August 2004, we entered into a contract to purchase 1,540 aluminum railcars from Freight Car America, formerly Johnstown America Corporation, to be used for the transportation of low sulfur coal from Wyoming to NRG's coal burning generating plants, including our New York and South Central facilities. On February 18, 2005, we entered into a ten-year operating lease agreement with GE Railcar Services Corporation, or GE, for the lease of 1,500 railcars. The lease was amended on August 2, 2005 to include an additional 40 railcars, bringing the total number of leased railcars to 1,540. Delivery of the railcars from

Freight Car America commenced in February 2005 and was completed by August 2005. We have assigned certain of our rights and obligations for the 1,540 railcars under the purchase agreement with Freight Car America to GE. Accordingly, the railcars which we lease from GE under the arrangement described above were purchased by GE from Freight Car America in lieu of our purchase of those railcars.

Coal Purchase and Transportation Commitments

In March 2005, we entered into an agreement to purchase 23.75 million tons of coal over a period of four years and nine months from Buckskin Mining Company, or Buckskin. The coal will be sourced from Buckskin's mine in the Powder River Basin, Wyoming, and will be used primarily in NRG Energy's coal-burning generation plants in the South Central region. Future payments under this agreement and other outstanding agreements for the years ending after December 31, 2005 are estimated as follows:

	Total (In millions)
2006	$ 192
2007	106
2008	48
2009	49
2010	3
Thereafter	18
Total	$ 416

International

Two of our wholly-owned, indirect subsidiaries are severally responsible for the prorate payments of principal, interest and related costs incurred in connection with the financing of our equity investment in the unincorporated joint venture Gladstone Power Station. At December 31, 2005, we were obligated for the loan of AUD 88 million (approximately US $65 million) in principal. This loan is scheduled to be fully repaid on March 31, 2009.

NRG FinCo Settlement

In May 2001, our wholly-owned subsidiary, NRG FinCo, entered into a $2.0 billion revolving credit facility. The facility was established to finance the acquisition, development and construction of certain power generating plants located in the United States and to finance the acquisition of turbines for such facilities. The facility provided for borrowings of base rate loans and Eurocurrency loans and was secured by mortgages and security agreements in respect of the assets of the projects financed under the facility, pledges of the equity interests in the subsidiaries or affiliates of the borrower that own such projects, and by guaranties from each such subsidiary or affiliate. The NRG FinCo secured revolver was initially scheduled to mature on May 8, 2006; however, due to defaults hereunder by NRG FinCo and applicable guarantors, the lenders accelerated all outstanding obligations on November 6, 2002. As of our emergence from bankruptcy, $1.1 billion was outstanding under the facility, and there was an aggregate of approximately $58 million of accrued but unpaid interest and commitment fees. Of this, $842 million was allowed in unsecured claims under the NRG plan of reorganization, and was settled at the time of our emergence. The remaining balance will be satisfied when the NRG FinCo lenders exercise their perfected security interests in our Nelson, Audrain and Pike projects. During 2004, we sold our Nelson assets for approximately $20 million and certain assets of our Pike project for $17 million. The proceeds from these sales were paid to the lenders. As of December 31, 2005, we hold assets in our Audrain project, principally property, plant and equipment, and some remaining ancillary equipment in our Pike project of approximately $115 million and $3 million, respectively. Proceeds from the sale of these assets are owed to the NRG FinCo lenders, accordingly there are liabilities reflected in other bankruptcy settlement and within discontinued operations for the same amount on our consolidated balance sheet. We are in the process of marketing for sale the remaining Pike equipment on behalf of the NRG FinCo lenders. The

NRG FinCo lenders have authority under their perfected security interest to accept or reject all offers. On December 8, 2005, we entered into an Asset Purchase and Sale Agreement to sell all of the assets of Audrain to AmerenUE, a subsidiary of Ameren Corporation . Accordingly, we have classified Audrain as discontinued operations. The purchase price is $115 million and is expected to close in the second quarter of 2006. In accordance with a Term Sheet Agreement with the NRG FinCo lenders, we have the right to retain certain proceeds from the sale as a success fee. Accordingly, we expect to record a gain on the sale of $15 million upon closing.

NYISO Claims

In November 2002, NYISO notified us of claims related to New York City mitigation adjustments, general NYISO billing adjustments and other miscellaneous charges related to sales between November 2000 and October 2002. New York City mitigation adjustments totaled approximately $11 million. The issue related to NYISO's concern that NRG would not have sufficient revenue to cover subsequent revisions to its energy market settlements. As of December 31, 2005, NYISO held approximately $4 million in escrow for such future settlement revisions.

Legal Issues

Set forth below is a description of our material legal proceedings. Pursuant to the requirements of SFAS 5, *"Accounting for Contingencies,"* and related guidance, we record reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss is reasonably estimable. Because litigation is subject to inherent uncertainties and unfavorable rulings or developments could occur, there can be no certainty that we may not ultimately incur charges in excess of presently recorded reserves. A future adverse ruling or unfavorable development could result in future charges which could have a material adverse effect on NRG's consolidated financial position, results of operations or cash flows.

With respect to a number of the items listed below, management has determined that a loss is not probable or the amount of the loss is not reasonably estimable, or both. In some cases, management is not able to predict with any degree of substantial certainty the range of possible loss that could be incurred. Notwithstanding these facts, management has assessed each of these matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought and the probability of success. Management's judgment may, as a result of facts arising prior to resolution of these matters or other factors prove inaccurate and investors should be aware that such judgment is made subject to the known uncertainty of litigation.

In addition to the legal proceedings noted below, we are parties to other litigation or legal proceedings arising in the ordinary course of business. In management's opinion, the disposition of these ordinary course matters will not materially adversely affect our consolidated financial position, results of operations or cash flows.

The Company believes that it has valid defenses to the legal proceedings and investigations described below and intends to defend them vigorously. However, litigation is inherently subject to many uncertainties. There can be no assurance that additional litigation will not be filed against the Company or its subsidiaries in the future asserting similar or different legal theories and seeking similar or different types of damages and relief. Unless specified below, the Company is unable to predict the outcome of these legal proceedings and investigations may have or reasonably estimate the scope or amount of any associated costs and potential liabilities. An unfavorable outcome in one or more of these proceedings could have a material impact on the Company's consolidated financial position, results of operations or cash flows. The Company also has indemnity rights for some of these proceedings to reimburse the Company for certain legal expenses and to offset certain amounts deemed to be owed in the event of an unfavorable litigation outcome.

California Electricity and Related Litigation

NRG, WCP, WCP's four operating subsidiaries, Dynegy, Inc. and numerous other unrelated parties are the subject of numerous lawsuits arising based on events occurring in the California power market. The complaints primarily allege that the defendants engaged in unfair business practices, price fixing, antitrust violations, and other market "gaming" activities. Certain of these lawsuits originally commenced in 2000 and 2001, which seek unspecified treble damages and injunctive relief, were consolidated and made a part of a Multi-District Litigation proceeding before the U.S. District Court for the Southern District of California. In December 2002, the district court found that federal jurisdiction was absent and remanded the cases back to state court. On December 8, 2004, the U.S. Court of Appeals for the Ninth Circuit affirmed the district court in most respects. On March 3, 2005, the Ninth Circuit denied a motion for rehearing. On May 5, 2005, the case was remanded to California state court and, under a scheduling order, defendants filed their objections to the pleadings. On July 22, 2005, based upon the filed rate doctrine and federal preemption, the court dismissed NRG Energy, Inc. without prejudice, leaving only subsidiaries of WCP remaining in the case. On October 3, 2005, the court sustained defendants' demurrer dismissing the case against all remaining defendants. On December 2, 2005, the plaintiffs filed their notice of appeal from the dismissal.

In addition to the cases discussed above, other cases, including putative class actions, have been filed in state and federal court on behalf of business and residential electricity consumers that name NRG and/or WCP and/or certain subsidiaries of WCP, in addition to numerous other defendants. The complaints allege the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades, and violated California's antitrust law and unfair business practices law. The complaints seek restitution and disgorgement, civil fines, compensatory and punitive damages, attorneys' fees and declaratory and injunctive relief. Motion practice is proceeding in these cases and dispositive motions have been filed in several of these proceedings. In the above referenced cases relating to natural gas, Dynegy is defending WCP and/or its subsidiaries pursuant to an indemnification agreement and will be the responsible party for any loss. In cases relating to electricity, Dynegy's counsel is representing it and WCP and/or its subsidiaries with each party responsible for half of the costs and each party shall be responsible for half of any loss. Where NRG is named as a party in an electricity case, it is defending the case and bears its own costs of defense.

FERC Proceedings

There are proceedings in which WCP and WCP subsidiaries are parties, which either are pending before FERC or on appeal from FERC to various U.S. Courts of Appeal. These cases involve, among other things, allegations of physical withholding, a FERC-established price mitigation plan determining maximum rates for wholesale power transactions in certain spot markets, and the enforceability of, and obligations under, various contracts with, among others, the Cal ISO, the California Department of Water Resources, or CDWR, and the State of California. The CDWR claim involves a February 2002 complaint filed by the State of California demanding that FERC abrogate the CDWR contract between the State and subsidiaries of WCP and seeking refunds associated with revenues collected from CDWR by WCP. In 2003, FERC rejected this demand and subsequently denied rehearing. The case was appealed to the U.S. Court of Appeals for the Ninth Circuit where all briefs were filed and oral argument was held December 8, 2004. Dynegy is indemnified by WCP and WCP is responsible for any loss unless any such loss resulted from Dynegy's gross negligence or willful misconduct.

New York Operating Reserve Markets

Consolidated Edison and others petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of FERC's refusal to order a re-determination of prices in the New York Independent System Operator, or NYISO, operating reserve markets for a two month period in 2000. On November 7, 2003, the court found that NYISO's method of pricing spinning reserves violated the NYISO tariff. On March 4, 2005, FERC issued an order favorable to NRG stating that no refunds would be required for the tariff violation associated with the pricing of spinning reserves. In the order, FERC also stated that the exclusion of the Blenheim-Gilboa facility and western reserves from the non-spinning market was not a market flaw and

NYISO was correct not to use its authority to revise the prices in this market. A motion for rehearing of the order was filed before the April 3, 2005 deadline and on November 17, 2005 FERC denied rehearing.

Connecticut Congestion Charges

On November 28, 2001, CL&P sought recovery in the U.S. District Court for Connecticut for amounts it claimed were owed for congestion charges under the October 29, 1999 Standard Offer Services Contract. CL&P withheld approximately $30 million from amounts owed to PMI under contract and PMI counterclaimed. CL&P's motion for summary judgment, which PMI opposed, remains pending. We cannot estimate at this time the overall exposure for congestion charges for the term of the contract prior to the implementation of standard market design, which occurred on March 1, 2003; however, such amount has been fully reserved as a reduction to outstanding accounts receivable.

New York Public Interest Research Group

On October 24, 2005, the U.S. Court of Appeals for the Second Circuit issued its opinion in *New York Public Interest Research Group (NYPIRG) v. Stephen L. Johnson, Administrator, U.S. Environmental Protection Agency*. In 2000, the NYSDEC issued a NOV to the prior owner of the Huntley and Dunkirk stations. After an unsuccessful challenge to the stations' Title V air quality permits by NYPIRG, it appealed. The Second Circuit held that, during the Title V permitting process for the two stations, the 2000 NOV should have been sufficient for the NYSDEC to have made a finding that the stations were out of compliance. Accordingly, the court stated that the EPA should have objected to the Title V permits on that basis and the permits should have included compliance schedules. On June 3, 2005, the consent decree among NYSDEC, Niagara Mohawk Power Corporation and NRG was entered in federal court, settling the substantive issues discussed by the Second Circuit in its decision. NYSDEC is in the process of incorporating the consent decree obligations into the Huntley and Dunkirk Title V permits so as to make them permit conditions, an action we believe is supported by the decision. On January 12, 2006, the NYSDEC, the EPA and NRG filed individual petitions for rehearing with the Second Circuit. On January 31, 2006, the court denied the petitions of the NYSDEC and EPA. NRG's petition for rehearing en banc remains pending.

Station Service Disputes

On October 2, 2000, NiMo commenced an action against NRG in New York state court seeking damages related to NRG's alleged failure to pay retail tariff amounts for utility services at the Dunkirk Plant between June 1999 and September 2000. The parties agreed to consolidate this action with two other actions against the Huntley and Oswego Plants. On October 8, 2002, by stipulation and order, this action was stayed pending submission to FERC of some or all of the disputes in the action. The contingent loss from this case is approximately $26 million, and at this time we believe we are adequately reserved. In a companion action at FERC, NiMo asserted the same claims and legal theories, and on November 19, 2004, FERC denied NiMo's petition and ruled that the NRG facilities could net their service obligations over each 30 calendar day period from the day NRG acquired the facilities. In addition, FERC ruled that neither NiMo nor the New York Public Service Commission could impose a retail delivery charge on the NRG facilities because they are interconnected to transmission and not to distribution. On April 22, 2005, FERC denied NiMo's motion for rehearing. NiMo appealed to the U.S. Court of Appeals for the D.C. Circuit which, on May 12, 2005, consolidated the appeal with several pending station service disputes involving NiMo. All parties filed their briefs prior to the January 17, 2006 deadline.

On December 14, 1999, NRG acquired certain generating facilities from CL&P. A dispute arose over station service power and delivery services provided to the facilities. On December 20, 2002, as a result of a petition filed at FERC by Northeast Utilities Services Company on behalf of itself and CL&P, FERC issued an order finding that, at times when NRG is not able to self-supply its station power needs, there is a sale of station power from a third-party and retail charges apply. In August 2003, the parties agreed to submit the dispute to binding arbitration, however, the parties have yet to agree on a description of the dispute and on the appointment of a neutral arbitrator. The contingent loss from this case could exceed $5 million, and at this time we believe we are adequately reserved.

Itiquira Energetica, S.A.

NRG's Brazilian project company, Itiquira Energetica S.A., or Itiquira, the owner of a 156 MW hydro project in Brazil, is in arbitration with the former Engineering, Procurement and Construction, or EPC, contractor for the project, Inepar Industria e Construcoes, or Inepar. The dispute was commenced in arbitration by Itiquira in September of 2002 and pertains to certain matters arising under the EPC contract between the parties. Itiquira sought Real 140 million and asserted that Inepar breached the contract. Inepar sought Real 39 million and alleged that Itiquira breached the contract. On September 2, 2005, the arbitration panel ruled in favor of Itiquira, awarding it Real 139 million and Inepar Real 4.7 million. Due to interest accrued from the commencement of the arbitration to the award date, Itiquira's award is increased to approximately Real 227 million (approximately $97 as of December 31, 2005). Itiquira has commenced the lengthy process in Brazil to execute on the arbitral award. We are unable to predict the outcome of this execution process. On October 14, 2005, Inepar filed with the arbitration panel a request for clarifications of the ruling and Itiquira objected. On December 21, 2005, Inepar's request for clarifications was denied. Due to the uncertainty of the collection process, NRG is accounting for receipt of any amounts as a gain contingency.

CFTC Trading Litigation

On July 1, 2004, the Commodities Futures Trading Commission, or CFTC, filed a civil complaint against NRG in Minnesota federal district court, alleging false reporting of natural gas trades from August 2001 to May 2002, and seeking an injunction against future violations of the Commodity Exchange Act. On November 17, 2004, a bankruptcy court hearing was held on the CFTC's motion to reinstate its expunged bankruptcy claim, and on NRG's motion to enforce the provisions of the NRG plan of reorganization, thereby precluding the CFTC from continuing its federal court action. The bankruptcy court has yet to schedule a hearing or rule on the CFTC's pending motion to reinstate its expunged claim. On December 6, 2004, a federal magistrate judge issued a report and recommendation that NRG's motion to dismiss be granted. That motion to dismiss was granted by the federal district court in Minnesota on March 16, 2005. On May 13, 2005 the CFTC filed a notice of appeal with the U.S. Court of Appeals for the Eighth Circuit. The CFTC filed its brief on August 9, 2005, and on September 29, 2005 NRG filed its brief. On October 28, 2005, the CFTC filed its reply brief.

Disputed Claims Reserve

As part of the NRG plan of reorganization, we have funded a disputed claims reserve for the satisfaction of certain general unsecured claims that were disputed claims as of the effective date of the plan. Under the terms of the plan, as such claims are resolved, the claimants are paid from the reserve on the same basis as if they had been paid out in the bankruptcy. To the extent the aggregate amount required to be paid on the disputed claims exceeds the amount remaining in the funded claims reserve, we will be obligated to provide additional cash and common stock to the satisfy the claims. Any excess funds in the disputed claims reserve will be reallocated to the creditor pool for the pro rata benefit of all allowed claims. The contributed common stock and cash in the reserves is held by an escrow agent to complete the distribution and settlement process. Since we have surrendered control over the common stock and cash provided to the disputed claims reserve, we recognized the issuance of the common stock as of December 6, 2003 and removed the cash amounts from our balance sheet. Similarly, we removed the obligations relevant to the claims from our balance sheet when the common stock was issued and cash contributed.

The face amount of the remaining unresolved claims is approximately $35 million, plus unresolved claims relating to the California power crisis in 2000-2001 and other claims of indefinite amount, but the Company estimates that the actual amount of these claims, once settled, will be less than $35 million. Based on these estimates, the Company believes that in order to assure sufficient funds to satisfy all remaining disputed claims the reserve needs to retain approximately $7 million in cash and approximately 650,000 shares of common stock. The reserve currently holds cash and stock in excess of these amounts, and the Company intends to make a supplemental distribution of the surplus on or about April 1, 2006. The total value of the planned distribution is approximately $137 million, based on the closing stock price on March 3, 2006, consisting of approximately $25 million in cash and 2,541,000 shares of NRG common stock. NRG's chapter 11 creditors holding allowed claims in Class 5 are expected to receive approximately $22.13 per $1,000.00 of allowed claim, consisting of $4.05 in cash and 0.41 shares of NRG common stock. Creditors holding Class 6 allowed claims are expected to receive approximately $19.97 per $1,000.00 of allowed claim, consisting of $1.89 in cash and 0.41 shares of NRG common stock.

Note 26 — Regulatory Matters

With the exception of NRG's Thermal and Chilled Water business, NRG's operations are not regulated operations subject to SFAS 71 and NRG does not record assets and liabilities that result from the regulated ratemaking processes in the same manner as do regulated public utilities. NRG does operate, however, in a highly regulated industry and we are subject to regulation by various federal and state agencies. As such we are affected by regulatory developments in the regions in which we operate.

Northeast Region

RMR Agreements

During 2005, NRG's Devon, Middleton and Montville stations operated under RMR agreements with ISO-NE that expired at the end of 2005. On November 1, 2005, NRG filed new RMR agreements with FERC in order provide for the continued provision of reliability services from these resources. Following the filing of interventions and protests challenging the proposed rates and provisions of the filed RMR agreements, NRG entered into a settlement agreement with the Connecticut Department of Public Utility Control, the Connecticut Office of Consumer Counsel, and ISO-NE that was filed with FERC on December 20, 2005, and that provided for the acceptance of new RMR agreements as described below, or Settlement RMR Agreements. The Commission accepted the Settlement RMR Agreements on February 1, 2006, establishing rates effective January 1, 2006 and effect immediately upon the expiration of the existing RMR agreements.

Under the Settlement RMR Agreements, NRG is entitled to annual fixed revenue requirement of $98 million, allocated among the stations, subject to NRG meeting the availability requirements specified therein. In addition, NRG is also entitled to retain 35% of its market revenues from the subject stations, while crediting 65% of such revenues against the monthly availability payments there under. The Settlement RMR Agreements specify that they remain in effect until a Location Installed Capacity market, or LICAP, or other similar capacity payment mechanism, is fully implemented or as FERC may otherwise determine if it approves a transition program for LICAP. In addition, the Settlement RMR Agreements contain some new termination provisions. For example, the Devon RMR agreement will terminate ninety days after the commencement of Locational Forward Reserve Market, but no earlier than January 1, 2007. In certain circumstances, after January 1, 2007, the Connecticut entities will be allowed to seek termination by filing a Section 206 complaint at FERC.

On February 15, 2006, we reported to FERC and to ISO-NE that for two days in January 2006, after unit 12 at Devon had been removed from service for needed maintenance, the unit was erroneously reported to ISO-NE as available. We further reported that when ISO-NE dispatched the Devon units on January 25, 2006, and unit 12 was unable to respond, inaccurate information was provided to ISO-NE. We are investigating the matter and are cooperating with FERC and ISO-NE.

LICAP Market Developments

On August 31, 2004, ISO-NE filed its proposal for designing and implementing a Location Installed Capacity market, or LICAP, with FERC. On June 15, 2005, the FERC administrative law judge assigned to the proceeding issued her decision, recommending that FERC approve ISO-NE's proposed LICAP design with a few modifications. On August 10, 2005, FERC issued an order delaying the implementation of a LICAP market from January 1, 2006 until October 1, 2006, and, in subsequent orders, assigned the proceeding to a settlement judge and required the commencement of settlement negotiations.

On January 31, 2006, the settlement judge reported to FERC that an agreement had been reached that provides for interim capacity payments for all generators in New England and the establishment of a forward procurement market design. The settlement includes over 100 parties, including suppliers, load-serving entities, state regulators, and ISO-NE. The settlement is not final and, moreover, it is not unanimous, and thus there is some possibility of continued litigation regarding LICAP and/or the settlement proposal. NRG supports the settlement in principle, and will continue to work to finalize the settlement. For our Connecticut units subject to the Settlement RMR Agreements, any transition payment will be credited against the monthly availability payment for those units, resulting in no additional revenues for those units. Our other New England generation units are expected to be eligible for the transition payments, and thus we expect the transition period to be net positive as compared to the status quo. The forward procurement market concept, when implemented, should provide a competitive market price for all our capacity, while enhancing opportunities for NRG to competitively repower its New England facilities.

Connecticut

On September 12, 2005, Richard Blumenthal, Attorney General for the state of Connecticut, the Connecticut Office of Consumer Counsel, the Connecticut Municipal Electric Energy Cooperative and the Connecticut Industrial Energy Consumers filed a complaint against ISO-NE pursuant to sections 206 and 212 of the Federal Power Act, seeking to amend the ISO-NE's Market Rule 1 to require all electric generation facilities not currently operating under an RMR agreement in Connecticut to be placed under cost-of-service rates. On October 20, 2005, NRG, among others, filed an answer requesting that the Commission dismiss the complaint. NRG's Connecticut Jet Power and Norwalk facilities are not currently operating pursuant to an RMR agreement.

New York

NRG's New York City generation is presently subject to price mitigation in the installed capacity market. When the capacity market is tight, the price NRG receives is capped by the mitigation price. However when the New York City capacity market is not tight, such as during the winter season, the proposed demand curve price levels should increase revenues from capacity sales over revenues obtained in previous capacity markets. On January 7, 2005, NYISO filed its proposed installed capacity, or ICAP, demand curves for the following capacity years: 2005-06, 2006-07 and 2007-08. On April 21, 2005, FERC accepted the NYISO's proposed demand curves, with certain minor revisions. Based upon NYISO's May 20, 2005 compliance filing, the monthly reference point for the demand curve is $14.34 per KW/month of ICAP for the 2006-207 capacity year. Following the New York State Reliability Council's, or NYSRC, report on the ICAP requirement for 2006-2007, on February 9, 2006, NYISO raised the New York City location capacity requirement to 83% from 80%. The existing in-city mitigation measures, however, will continue to apply to us when the capacity market is tight, preventing us from obtaining these higher prices.

On October 6, 2005, NiMo filed a complaint against NYISO and the NYSRC requesting that FERC direct the NYSRC to modify its methodology for calculating the statewide installed reserve margin. NiMo's complaint also alleges that the NYISO incorrectly calculates the installed capacity requirement. FERC issued an order on February 2, 2006, denying NiMo's complaint and directing that the NiMO work with NYISO and NYSRC to modify its methodology for calculating the statewide Installed Reserve Margin.

The dispute is continuing with respect to high prices for spinning reserves, or SRs, and non-spinning reserves, or NSR, in the NYISO-administered markets during the period from January 29 to March 27, 2000. Certain entities have argued that the NYISO acted unreasonably is declining to invoke Temporary Extraordinary Operating Procedures, or TEPs, to recalculate prices and the markets should be resettled for various reasons. In a series of orders, FERC declined to grant the requested relief. On appeal, the U.S. Court of Appeals for the D.C. Circuit, or DC Circuit, remanded the case to FERC to further explain its decision not to utilize TEP to remedy certain market issues. On March 4, 2005, FERC issued an order reaffirming that (i) the NYISO acted reasonably in not invoking its TEP, (ii) NYISO did not violate its tariff, and (3) refunds should not be granted, and this order was reaffirmed on rehearing on November 17, 2005. These orders have been appealed to the D.C. Circuit.

A similar dispute remains with respect to high prices in the NYISO energy market on May 8 and 9, 2000 Those high prices resulted from bids submitted by the New York Power Authority for its Blenheim-Gilboa facility, a pumped storage unit. Certain parties have challenged NYISO's issuance of an Energy Limited Resources Extraordinary Corrective Action utilizing its TEP authority to reduce the prices and complained to FERC requesting NYISO restore the original real-time market prices. The Commission denied the complaints. On appeal, the D.C. Circuit found that FERC had not adequately addressed the complainants' contention that there was no Market Design Flaw that forced NYPA to submit high bids for Blenheim-Gilboa facility and remanded the case to FERC. In its March 4, 2005 order on remand, FERC found that NYISO's tariff did not contain a market design flaw, a necessary prerequisite to invoking TEP. FERC therefore ordered NYISO to pay refunds and collect surcharges designed to reinstate the original market clearing prices for energy for the real-time market determined on May 8 and 9, 2000, and to file a refund report; this order was reaffirmed on rehearing. These orders have been appealed to the D.C. Circuit. Also on rehearing, the Commission set for settlement and hearing proceedings the issues raised as to the amount of refunds and the means by which NYISO may determine them (i.e., the calculation of the refund amount), the determination of opportunity costs, and the determination and treatment of amounts that the NYISO may be unable to collect from its customers,

On December 9, 2005, NYISO submitted proposed revisions to its tariff to include negotiated compensation provisions for existing generators providing "Black Start and System Restoration Services" (Black Start and System Restoration Services) in the Consolidated Edison Company of New York, Inc.'s, or ConEd, transmission district. NRG's Arthur Kill and Astoria Gas Turbine facilities provide such blackstart services and NRG supports NYISO's filing. On January 27, 2006, FERC issued a deficiency letter requiring NYISO to provide additional cost support for its filing.

The rate that the NRG generation facilities in New York are currently paid for voltage support service, or VSS, was scheduled to expire on December 31, 2005. On December 5, 2005, the NYISO filed for an extension of the VSS rate for a period of 120 days (from January 1 to April 4, 2006). On December 30, 2005, FERC issued an order accepting the NYISO's proposed extension, subject to refund, and referring the proceeding to the FERC's Dispute Resolution Service. Settlement discussions are ongoing.

Mid Atlantic

On August 31, 2005, PJM filed a proposed reliability pricing model, or RPM, that, if accepted by FERC, would modify the capacity obligations imposed on load, and related market mechanisms within PJM. The primary features of the RPM proposal are the establishment of locational capacity markets using a downward-sloping demand curve similar to the demand curve model adopted in New York; a four-year-forward commitment of capacity resources; establishing separate obligations and auction procurement mechanisms for quick start and load following resources; allowing certain planned resources, transmission upgrades and demand resources to compete with existing generation resources to satisfy capacity requirements; and market power mitigation rules (which are primarily applied to existing generation resources, such as NRG's). On October 19, 2005, NRG filed an intervention and protest in response to the PJM RPM proposal. On December 8, 2005, FERC issued a notice establishing a technical conference on the issues raised by PJM's RPM filing which was conducted on February 2, 2006. The outcome of this proceeding is not possible to predict with certainty, nor is the timing of any implementation of PJM's proposed RPM model.

On November 16, 2005, PJM filed a comprehensive settlement agreement establishing new scarcity pricing rules for the PJM markets, as well as clarifying the circumstances of when suppliers will be subject to offer caps with respect to transmission constraints. The settlement agreement addresses certain issues involving the mitigation of market power that may result from congestion in PJM's service territory, provisions for scarcity pricing, increased payments to frequently mitigated units, and competitive issues surrounding certain of PJM's internal interfaces. NRG's facilities may be located in the scarcity pricing regions, and furthermore, are mitigated a high percentage of the time and thus may be impacted by these changes. The settlement agreement and related tariff provisions were accepted by FERC effective January 26, 2006.

South Central Region

On January 3, 2005, Entergy submitted a petition for declaratory order requesting guidance on issues associated with its proposal to establish an independent coordinator of transmission, or ICT. Entergy requested FERC's guidance on whether the functions to be performed by the ICT will cause it to become a public utility under the Federal Power Act or the transmission provider under Entergy's Open Access Transmission Tariff, or OATT, and whether Entergy's transmission pricing proposal satisfies FERC's transmission pricing policy.

On March 22, 2005, FERC granted Entergy's Petition for declaratory order, stating that the implementation of the ICT proposal on an experimental basis will permit a transmission decision-making process that is independent of control by any market participant or class of participants. On May 23, 2005, FERC issued an order granting rehearing for further consideration but has not yet acted on rehearing. On May 27, 2005, Entergy submitted a Section 205 filing detailing the enhanced functions that the ICT will perform. Numerous interventions and protests were filed in response, a technical conference has been held and the proceeding is ongoing.

Western Region

NRG has negotiated RMR agreements with the Cal ISO for one-year terms for all of the WCP capacity. NRG has filed these RMR agreements with FERC, with an effective date of January 1, 2006, for each of our Encina and Cabrillo II plants, and these RMR agreements have been accepted by FERC. Unit 4 was not designated by Cal ISO as RMR unit for 2006 until December 22, 2005, and its RMR agreement was accepted separately by FERC on February 14, 2006. MML Energy North America, LLC protested the RMR agreement for Unit 4 by Cal ISO and has requested rehearing of the order. Cal ISO did not designate the El Segundo plant as an RMR for 2006. A tolling agreement for the total capacity of the El Segundo plant has been executed with a major load serving entity for the period May 2006 through April 2008.

All of our California plants are subject to FERC's "must-offer" requirements requiring any generator capable of operating and not subject to a bilateral agreement to make its capacity available to Cal ISO. On January 13, 2006, FERC accepted Cal ISO's proposal to increase the "softcap" from $250 to $400 per MWh effective January 1, 2006, and declined to convert the softcap to a firm price-cap.

Note 27 — Environmental Matters

The construction and operation of power projects are subject to stringent environmental and safety protection and land use laws and regulation in the U.S. If such laws and regulations become more stringent, or new laws, interpretations or compliance policies apply and our facilities are not exempted from coverage, we could be required to make extensive modifications to further reduce potential environmental impacts. In general, the effect of future laws or regulations is expected to require the addition of pollution control equipment or the imposition of restrictions on our operations.

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products located at the facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by the party in connection with any releases or threatened releases. These laws impose strict (without fault) and joint and several liability. The cost of investigation, remediation or removal of any hazardous or toxic substances or petroleum products could be substantial. On January 18, 2006, NRG Indian River Operations, Inc. received a letter of informal notification from DNREC stating that it may be a potentially responsible party with respect to the Burton Island Landfill, along with Delmarva Power. The letter signals only that an investigation is to be commenced and is not a conclusive determination. Further, the Burton Island Landfill is a site that would potentially qualify for a remedy under a "Voluntary Cleanup Program" or VCP. We have signaled our interest in being considered for a VCP should matters progress. With the exception of the foregoing, NRG has not been named as a potentially responsible party with respect to any off-site waste disposal matter.

As part of acquiring existing generating assets, we have inherited certain environmental liabilities associated with regulatory compliance and site contamination. Often potential compliance implementation plans are changed, delayed or abandoned due to one or more of the following conditions: (a) extended negotiations with regulatory agencies, (b) a delay in promulgating rules critical to dictating the design of expensive control systems, (c) changes in governmental/regulatory personnel, (d) changes in the interpretation and enforcement of existing laws and regulations, (e) changes in governmental priorities or (f) selection of a less expensive compliance option than originally envisioned.

Trust funds — during our period of bankruptcy as well as inherited circumstances in our South Central region, we deposited approximately $20 million in trust funds to maintain financial assurance to cover costs associated with a number of future remediation items. Our Northeast region has a total of approximately $15 million in trust funds and our South Central has approximately $5 million in trust funds as described in the discussions below.

Northeast Region. Significant amounts of ash are contained in landfills at on and off-site locations. At Dunkirk, Huntley, Somerset and Indian River, ash is disposed of at landfills owned and operated by NRG. NRG maintains financial assurance to cover costs associated with landfill closure, post-closure care and monitoring activities. NRG has funded a trust in the amount of approximately $6 million to provide such financial assurance in New York and approximately $7 million in Delaware. NRG must also maintain financial assurance for closing interim status "RCRA (Resource Conservation and Recovery Act) facilities" at the Devon, Middletown, Montville and Norwalk Harbor Generating Stations and has funded a trust in the amount of approximately $2 million accordingly.

NRG inherited historical clean-up liabilities when it acquired the Somerset, Devon, Middletown, Montville, Norwalk Harbor, Arthur Kill and Astoria Generating Stations. During installation of a sound wall at Somerset Station in 2003, oil contaminated soil was encountered. NRG has delineated the general extent of contamination, determined it to be minimal, and has placed an activity use limitation on that section of the property. Site contamination liabilities arising under the Connecticut Transfer Act at the Devon, Middletown, Montville and Norwalk Harbor Stations have been identified. NRG has proposed a remedial action plan to be implemented over the next two to eight years (depending on the station) to address historical ash contamination at the facilities. The total estimated cost is not expected to exceed $1.4 million. Remedial obligations at the Arthur Kill generating station have been established in discussions between NRG and the NYSDEC and are estimated to be approximately $1 million. Remedial investigations continue at the Astoria generating station with long-term clean-up liability expected to be approximately $3 million. While installing groundwater-monitoring wells at Astoria to track our remediation of an historical fuel oil spill, the drilling contractor encountered deposits of coal tar in two borings. NRG reported the coal tar discovery to the NYSDEC in 2003 and delineated the extent of this contamination. NRG may also be required to remediate the coal tar contamination and/or record a deed restriction on the property if significant contamination is to remain in place.

In September 2001, we experienced an underground fuel line leak at our Vienna Generating Station, resulting in a small release of oil free product, which was contained. NRG promptly reported the event to the relevant state agencies and continues to work with the Maryland Department of the Environment, or DEP, to develop any remediation requirements. Ongoing monitoring has indicated that the product is stable. NRG submitted a site assessment report and proposed remediation plan to Maryland DEP but the agency has not formally responded to those documents. Based upon work completed by a remediation contractor retained by NRG, long-term clean up liability in connection with this matter is not expected to exceed $1 million.

We currently estimate that we will incur total environmental capital expenditures of approximately $367 million during 2006 through 2011 for the facilities in New York, Connecticut, Delaware and Massachusetts. These expenditures will be primarily related to installation of particulate, SO_2 and NOX controls, as well as installation of BTA under the Phase II 316(b) Rule.

South Central Region

South Central Region. Liabilities associated with closure, post-closure care and monitoring of the ash ponds owned and operated on site at the Big Cajun II Generating Station are addressed through the use of a trust fund maintained by NRG in the amount of approximately $5 million. Annual payments are made to the fund in the amount of approximately $0.1 million.

We currently estimate approximately $252 million of capital expenditures will be incurred during the period 2006 through 2011 for our South Central facilities, primarily related to installation of particulate, SO_2 and NOx controls, as well as studies for installation of BTA under the Phase II 316(b) Rule.

Western Region

Western Region. The Asset Purchase Agreements for the Long Beach, El Segundo, Encina, and San Diego gas turbine generating facilities provide that SCE and San Diego Gas & Electric or SDG&E, as sellers retain liability, and indemnify NRG, for existing soil and groundwater contamination that exceeds remedial thresholds in place at the time of closing. NRG and its business partner identified existing contamination and provided the results to the sellers. SCE and SDG&E agreed to address this identified contamination and are undertaking corrective action at the Encina and San Diego gas turbine generating sites. NRG could incur related costs if SCE and SDG&E did not complete their corrective action responsibilities. Spills and releases of various substances have occurred at these sites since NRG established the historical baseline, all of which have been, or will be, completely remediated. An oil leak in 2002 from underground piping at the El Segundo Generating Station contaminated soils adjacent to and underneath the Unit 1 and 2 powerhouse. NRG excavated and disposed of contaminated soils to the greatest extent permitted by existing laws. Following NRG's formal request, the Los Angeles Regional Water Quality Control Board agreed to allow the remaining contaminated soils to stay underneath the building foundation until the building is demolished.

A diesel fuel spill to on-site surface containment occurred at the Cabrillo Power II LLC Kearny Combustion Turbine facility (San Diego) in February 2003. Emergency response and subsequent remediation activities were completed. Confirmation sampling for the site was completed in 2004 and submitted to the San Diego County Department of Environmental Health. Three San Diego Combustion Turbine facilities, formerly operating pursuant to land leases with the U.S. Navy, are currently being decommissioned with equipment being removed from the sites and remediation activities occurring where necessary. All remedial activities are being completed pursuant to the requirements of the U.S. Navy and the San Diego County Department of Environmental Health. Remediation activities were completed in 2004 at the Naval Training Center and North Island facilities. At the 32nd Street Naval Station facility, additional contamination delineation is necessary and additional un-quantified remediation in inaccessible areas may be required in the future. Given the current uncertainties at this facility, it is difficult to accurately estimate the resultant clean up liability.

Other North America

Resource Recovery. Liabilities associated with closure, post-closure care and monitoring of the Becker refuse derived fuel ash landfill are addressed through the use of a letter of credit maintained by NRG in the amount of approximately $3 million.

Note 28 — Cash Flow Information

Detail of supplemental disclosures of cash flow and non-cash investing and financing information was:

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
Interest paid (net of amount capitalized)	$ 257	$ 295	$ 87	$ 182
Income taxes paid	21	34	2	27
Non-cash investing and financing activities:				
Investment in WCP by contributing fixed assets	—	2	—	—
Reduction to fixed assets due to liquidated damages	—	15	—	—
Addition to fixed assets due to conditional asset retirement obligations	4	—	—	—
Conversion of accrued salaries to stockholders' equity	2	—	—	—
Addition to treasury stock for the maximum purchase price adjustment	8	—	—	—
Accrued deferred acquisition costs	2	—	—	—

Note 29 — Guarantees and Other Contingent Liabilities

In November 2002, the FASB issued FIN 45. In connection with the adoption of Fresh Start, all outstanding guarantees were considered new; accordingly, we applied the provisions of FIN 45 to all of the guarantees.

We and our subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of our business activities. Examples of these contracts include asset purchase and sale agreements, commodity sale and purchase agreements, joint venture agreements, operations and maintenance agreements, service agreements, settlement agreements, and other types of contractual agreements with vendors and other third parties. These contracts generally indemnify the counter-party for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements. In many cases, our maximum potential liability cannot be estimated, since some of the underlying agreements contain no limits on potential liability. In accordance with FIN 45, we estimated that the current fair value for issuing these guarantees is approximately $15 million as of December 31, 2005 and the liability in this amount is included in our other long term obligations.

The material guarantees, within the scope of FIN 45, are as follows:

- **Standby letters of credit and surety bonds** — At December 31, 2005, we and our consolidated subsidiaries were contingently obligated for a total of approximately $321 million under standby letters of credit. Most of these letters of credit are issued in support of our obligations to perform under commodity agreements, financing or other arrangements. These letters of credit expire within one year of issuance, and it is typical for us to renew many of them on similar terms.

  As of December 31, 2005, standby letters of credit in amounts totaling approximately $312 million were issued under our $350.0 million corporate funded letter of credit facility, which is reflected in our financial statements. Of this amount, approximately $3 million was issued to support performance obligations of an unconsolidated affiliate of ours. Our Flinders subsidiary had issued approximately

AUD 12 million (approximately US $9 million) in unfunded letters of credit under an AUD 20 million (approximately US $15 million) working capital and letter of credit facility, described in Note 17 — Debt and Capital Leases.

At December 31, 2005, we were also contingently obligated for approximately $4 million under surety bonds to support our prepayment, completion, license, tax or performance bonding requirements. Most of the bonds are supported by a letter of credit under our funded letter of credit facility, which is reflected in our financial statements. All of the bonds expire within one year; however, we expect to renew many of these bonds on a rolling twelve-month basis.

- **Asset purchases and divestitures** — In the normal course of business, we may be asked to provide certain assurances to the counter-parties of our asset sale and purchase agreements. Such assurances may take the form of a guarantee issued by us on behalf of a directly or indirectly held majority-owned subsidiary who included certain indemnifications to a third party (usually the buyer) as described below. Due to the inter-company nature of such arrangements (NRG Energy is essentially guaranteeing its own performance) and the nature of the guarantee being provided (usually the typical representations and warranties that are provided in any asset sales agreement), it is not our policy to recognize the value of such an obligation in our consolidated financial statements. Most of these guarantees provide an explicit cap on our maximum liability, as well as an expiration period, exclusive of breach of representations and warranties.

  On April 1, 2005, in conjunction with the sale of our interest in the Enfield Energy Center Ltd, a minority-owned, indirectly held affiliate of ours, we issued a guarantee of the obligations of a subsidiary of ours under the sale and purchase agreement, to the buyers of our interest. The maximum liability for this guarantee was approximately $56 million as of December 31, 2005.

  At December 31, 2005, our maximum known exposure under asset purchase or sales guarantees was approximately $123 million. On January 1, 2006, we executed a guarantee to a prospective buyer of one of our unconsolidated affiliates. This guarantees the payment of claims related to tax obligations, late payments, and indemnifications, and the maximum liability we estimate under this guarantee is approximately $5 million. This guarantee expires on October 1, 2016. Upon the defeasance of $0.4 million of our Second Priority Notes on February 2, 2006, we retained guarantee obligations related to this indebtedness. For further information, see Note 17 — Debt and Capital Leases.

- **Commercial sales arrangements** — In connection with the purchase and sale of fuel, emission allowances and power generation products to and from third parties with respect to the operation of some of our generation facilities in the U.S., we may be required to guarantee a portion of the obligations of certain of our subsidiaries. These obligations may include liquidated damages payments or other unscheduled payments. As of December 31, 2005, we estimate the maximum liability for this category of guarantee was approximately $91 million. We have subsequently issued additional guarantees or increased existing guarantees of the performance of NRG PMI, with increasing the maximum liability by approximately $19 million. These additional guarantees terminate between December 31, 2006 and December 31, 2008.

- **Other types of guarantees** — We have issued guarantees of obligations our subsidiaries may incur in provision of environmental site remediation, payment of debt obligations, rail car leases and performance under operating and maintenance agreements. Maximum quantifiable liability under the environmental guarantees is approximately $64 million, most of which is a guarantee for plant removal and site remediation obligations at our Flinders facilities. The maximum quantifiable exposure under the operational guarantees is $25 million, primarily related to our role as operator at the Gladstone power plant. In addition, we have a maximum liability exposure of approximately $1 million under a tax indemnity guarantee to a third party and third-party debt guarantee exposure of approximately $1 million.

On February 18, 2005 we executed a guarantee to the benefit of our counter-party under a railcar lease. We guarantee the performance and payment obligations of NRG PMI under the railcar lease. Payment obligations include future rental and termination payments, which are estimated to total approximately $48 million over the next five years of the lease, and approximately $46 million over the remainder of the lease, should we elect not to exercise our termination rights. If we do elect to terminate the lease, we will be required to pay $8 million in termination fees, but we will have no obligation to make future lease payments. However, our obligations under this guarantee include additional requirements that would be difficult to quantify until such time as a claim were made. As a result, our maximum potential obligation under this guarantee is of indeterminate exposure, and therefore is not included in the table of maximum exposure maturities in this note.

The following table outlines the scheduled expiration of our guarantees, indemnity and other contingent liability obligations, to the extent the maximum liabilities can be quantified and scheduled.

	Amount of Guarantee Liabilities Expiration per Period as of December 31, 2005 (in millions)				
Guarantee Type	**Total Amounts Committed**	**Short-term**	**2-3 Years**	**4-5 Years**	**After 5 Years or Indeterminate**
Funded standby letters of credit	$ 312	$ 312	$ —	$ —	$ —
Unfunded standby letters of credit	9	9	—	—	—
Surety bonds	4	4	—	—	—
Asset sales guarantee obligations	123	—	13	—	110
Commodity sales guarantee obligations	91	62	12	14	3
Other guarantees	91	—	1	—	90
Total guarantees	$ 630	$ 387	$ 26	$ 14	$ 203

The material indemnities, within the scope of FIN 45, are as follows:

- **Asset purchases and divestitures** — The purchase and sale agreements which govern our asset or share investments and divestitures customarily contain indemnifications of the transaction to third parties. The contracts indemnify the parties for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party, or as a result of a change in tax laws. These obligations generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or quantify at the time of the transaction. In several cases, the contract limits the liability of the indemnifier. For those indemnities in which liability is capped, the exposure ranges from $250 thousand up to $50 million. We have no reason to believe that we currently have any material liability relating to such routine indemnification obligations.

- **Other indemnities** — Other indemnifications we have provided cover operational, tax, litigation and breaches of representations, warranties and covenants. We have also indemnified, on a routine basis in the ordinary course of business, consultants or other vendors who have provided services to us. Our maximum potential exposure under these indemnifications can range from a specified dollar amount to an unlimited amount, depending on the nature of the transaction. Total maximum potential exposure under these indemnifications is not estimable due to uncertainty as to whether claims will be made or how they will be resolved. We do not have any reason to believe that we will be required to make any material payments under these indemnity provisions.

Because many of the guarantees and indemnities we issue to third parties do not limit the amount or duration of our obligations to perform under them, there exists a risk that we may have obligations in excess of the amounts described above. For those guarantees and indemnities that do not limit our liability exposure, we may not be able to estimate what our liability would be, until a claim was made for payment or performance, due to the contingent nature of these contracts.

Note 30 — Sales to Significant Customers

Reorganized NRG

For the year ended December 31, 2005 we derived approximately 50.2% of total revenues for majority owned operations from two customers: NYISO accounted for 35.6% and ISO-NE accounted for 14.6%. We account for the revenues attributable to these customers as part of our Northeast segment.

For the year ended December 31, 2004, we derived approximately 37.8% of our total revenues from majority-owned operations from two customers. NYISO accounted for 28.6% and ISO New England accounted for 9.2%. We account for these revenues attributable to NYISO and ISO New England as part of our Northeast segment.

For the period December 6, 2003 through December 31, 2003, we derived approximately 39.4% of our total revenues from majority-owned operations from two customers: NYISO accounted for 26.8% and ISO New England accounted for 12.6%. Revenues from NYISO and ISO New England are included in our Northeast segment.

Predecessor Company

For the period from January 1, 2003 through December 5, 2003, sales to one customer, NYISO, accounted for 33.4% of our total revenues from majority-owned operations.

Note 31 — Jointly Owned Plants

Big Cajun II Unit 3

On March 31, 2000, we acquired a 58% interest in the Big Cajun II, Unit 3 generation plant. Entergy Gulf States owns the remaining 42%. Big Cajun II, Unit 3 is operated and maintained by Louisiana Generating pursuant to a joint ownership participation and operating agreement. Under this agreement, Louisiana Generating and Entergy Gulf States are each entitled to their ownership percentage of the hourly net electrical output of Big Cajun II, Unit 3. All fixed costs are shared in proportion to the ownership interests. All variable costs are incurred in proportion to the energy delivered to the owners. Our income statement includes its share of all fixed and variable costs of operating the unit.

Reorganized NRG

Our 58% share of the property, plant and equipment at December 31, 2005 and 2004 was approximately $186 million and $185 million, respectively (included in this amount is construction in progress was $3 million and $2 million, respectively), and the corresponding accumulated depreciation and amortization was approximately $22 million and $12 million, respectively.

Keystone and Conemaugh

In June 2001, we completed the acquisition of an approximately 3.7% interest in both the Keystone and Conemaugh coal-fired generating facilities. The Keystone and Conemaugh facilities are located near Pittsburgh, Pennsylvania and are jointly owned by a consortium of energy companies. We purchased our interest from Conectiv, Inc. Keystone and Conemaugh are operated by GPU Generation, Inc., which sold its assets and operating responsibilities to Sithe Energies. Keystone and Conemaugh both consist of two operational coal-fired steam power units with a combined net output of 1,700 MW, four diesel units with a combined net output of 11 MW and an on-site landfill. The units are operated pursuant to a joint ownership participation and operating agreement. Under this agreement each joint owner is entitled to its ownership ratio of the net available output of the facility. All fixed costs are shared in proportion to the ownership interests. All variable costs are incurred in proportion to the energy delivered to the owners. Our income statement includes our share of all fixed and variable costs of operating the facilities.

Reorganized NRG

Our 3.70% and 3.72% share of the Keystone and Conemaugh facilities original cost included in property, plant and equipment at December 31, 2005 was approximately $59 million and $71 million, respectively (included in this amount is construction in progress in the amount of $1 million and $0 million, respectively). The corresponding accumulated depreciation and amortization at December 31, 2005 for Keystone and Conemaugh was approximately $6 million and $8 million, respectively.

Our 3.70% and 3.72% share of the Keystone and Conemaugh facilities property, plant and equipment at December 31, 2004 was approximately $59 million and $71 million, respectively. The corresponding accumulated depreciation and amortization at December 31, 2004 for Keystone and Conemaugh was approximately $3 million and $4 million, respectively.

Note 32 — Unaudited Quarterly Financial Data

Summarized quarterly unaudited financial data is as follows:

	Reorganized NRG				
	Quarters Ended 2005				
	March 31	June 30	September 30	December 31	Total Year
	(In millions, except per share data)				
Operating Revenues	$ 597	$ 579	$ 762	$ 770	$ 2,708
Operating Income/(Loss)	44	44	(7)	157	238
Income From Continuing Operations	22	22	(37)	70	77
Income/(Loss) on Discontinued Operations net of Income Taxes	1	2	10	(6)	7
Net Income/(Loss)	$ 23	$ 24	$ (27)	$ 64	$ 84
Weighted Average Number of Common Shares Outstanding — Basic	87	87	84	81	85
Income From Continuing Operations per Weighted Average Common Share — Basic	$ 0.20	$ 0.21	$ (0.51)	$ 0.79	$ 0.67
Income/(Loss) From Discontinued Operations per Weighted Average Common Share — Basic	0.01	0.02	0.12	(0.07)	0.09
Net Income per Weighted Average Common Share — Basic	$ 0.21	$ 0.23	$ (0.39)	$ 0.72	$ 0.76
Weighted Average Number of Common Shares Outstanding — Diluted	88	88	84	92	85
Income From Continuing Operations per Weighted Average Common Share — Diluted	$ 0.20	$ 0.20	$ (0.51)	$ 0.74	$ 0.66
Income From Discontinued Operations per Weighted Average Common Share — Diluted	0.01	0.02	0.12	(0.06)	0.09
Net Income per Weighted Average Common Share — Diluted	$ 0.21	$ 0.22	$ (0.39)	$ 0.68	$ 0.75

	Reorganized NRG				
	Quarters Ended 2004				
	March 31	June 30	September 30	December 31	Total Year
	(In millions, except per share data)				
Operating Revenues	$ 596	$ 570	$ 605	$ 577	$ 2,348
Operating Income	118	115	79	81	393
Income From Continuing Operations	31	69	44	17	161
Income/(Loss) on Discontinued Operations net of Income Taxes	(1)	14	10	2	25
Net Income	$ 30	$ 83	$ 54	$ 19	$ 186
Weighted Average Number of Common Shares Outstanding — Basic	100	100	100	99	100
Income From Continuing Operations per Weighted Average Common Share — Basic	$ 0.31	$ 0.69	$ 0.44	$ 0.17	$ 1.61
Income/(Loss) From Discontinued Operations per Weighted Average Common Share — Basic	(0.01)	0.14	0.10	0.01	0.25
Net Income per Weighted Average Common Share — Basic	$ 0.30	$ 0.83	$ 0.54	$ 0.18	$ 1.86
Weighted Average Number of Common Shares Outstanding — Diluted	100	100	101	99	100
Income From Continuing Operations per Weighted Average Common Share — Diluted	$ 0.31	$ 0.69	$ 0.44	$ 0.17	$ 1.60
Income From Discontinued Operations per Weighted Average Common Share — Diluted	(0.01)	0.14	0.10	0.01	0.25
Net Income per Weighted Average Common Share — Diluted	$ 0.30	$ 0.83	$ 0.54	$ 0.18	$ 1.85

For 2005 and for 2004, we have reclassified the financial results of Northbrook New York LLC, Northbrook Energy LLC and Audrain as discontinued operations. Accordingly, 2005 and 2004 quarterly results have been restated to report the results as discontinued.

Note 33 — Condensed Consolidating Financial Information

As of December 31, 2005, we have $1.08 billion of Second Priority Notes outstanding. The Second Priority Notes are guaranteed by each of current and future wholly-owned domestic subsidiaries, or Guarantor Subsidiaries. Each of the following Guarantor Subsidiaries fully and unconditionally guarantee the Second Priority Notes.

Arthur Kill Power LLC
Astoria Gas Turbine Power LLC
Berrians I Gas Turbine Power LLC
Big Cajun II Unit 4 LLC
Capistrano Cogeneration Company
Chickahominy River Energy Corp.
Commonwealth Atlantic Power LLC
Conemaugh Power LLC
Connecticut Jet Power LLC
Devon Power LLC
Dunkirk Power LLC
Eastern Sierra Energy Company
El Segundo Power II LLC
Hanover Energy Company
Huntley Power LLC
Indian River Operations Inc.
Indian River Power LLC
James River Power LLC
Kaufman Cogen LP
Keystone Power LLC
Louisiana Generating LLC
Middletown Power LLC
Montville Power LLC
NEO California Power LLC
NEO Chester-Gen LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Landfill Gas Holdings Inc.
NEO Power Services Inc.
Norwalk Power LLC
NRG Affiliate Services Inc.
NRG Arthur Kill Operations Inc.
NRG Asia-Pacific, Ltd.
NRG Astoria Gas Turbine Operations, Inc.
NRG Bayou Cove LLC
NRG Cabrillo Power Operations Inc.
NRG Cadillac Operations Inc.
NRG California Peaker Operations LLC
NRG Connecticut Affiliate Services Inc.
NRG Devon Operations Inc.
NRG Dunkirk Operations Inc.
NRG El Segundo Operations Inc.
NRG Huntley Operations Inc.
NRG International LLC
NRG Kaufman LLC
NRG Mesquite LLC
NRG MidAtlantic Affiliate Services Inc.
NRG Middletown Operations Inc.
NRG Montville Operations Inc.
NRG New Jersey Energy Sales LLC
NRG New Roads Holdings LLC
NRG North Central Operations Inc.
NRG Northeast Affiliate Services Inc.
NRG Norwalk Harbor Operations Inc.
NRG Operating Services, Inc.
NRG Oswego Harbor Power Operations Inc.
NRG Power Marketing Inc.
NRG Rocky Road LLC
NRG Saguaro Operations Inc.
NRG South Central Affiliate Services Inc.
NRG South Central Generating LLC
NRG South Central Operations Inc.
NRG West Coast LLC
NRG Western Affiliate Services Inc.
Oswego Harbor Power LLC
Saguaro Power LLC
Somerset Operations Inc.
Somerset Power LLC
Vienna Operations Inc.
Vienna Power LLC

The Second Priority Notes noted above were replaced on February 2, 2006 with new Senior Unsecured Notes which are described in Note 34–Subsequent Events. All of the Guarantor Subsidiaries listed above except for El Segundo Power II LLC, fully and unconditionally guarantee the new Senior Unsecured Notes.

The non-guarantor subsidiaries, or Non-Guarantor Subsidiaries, include all of our foreign subsidiaries and certain domestic subsidiaries. We conduct much of our business through and derive much of our income from our subsidiaries. Therefore, our ability to make required payments with respect to our indebtedness and other obligations depends on the financial results and condition of our subsidiaries and our ability to receive funds from our subsidiaries. Except for NRG Bayou Cove, LLC, which is subject to certain restrictions under our Peaker financing agreements, there are no restrictions on the ability of any of the Guarantor Subsidiaries to transfer funds to us. In addition, there may be restrictions for certain Non-Guarantor Subsidiaries.

The following condensed consolidating financial information presents the financial information of NRG Energy, Inc., the Guarantor Subsidiaries and the Non-Guarantor Subsidiaries in accordance with Rule 3-10 under the Securities and Exchange Commission's Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the Guarantor Subsidiaries or Non-Guarantor Subsidiaries operated as independent entities.

In this presentation, NRG Energy, Inc. consists of parent company operations. Guarantor Subsidiaries and Non-Guarantor Subsidiaries of NRG are reported on an equity basis. For companies acquired, the fair values of the assets and liabilities acquired have been presented on a "push-down" accounting basis.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2005
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[1]	Consolidated Balance
			(In millions)		
Operating Revenues					
Revenues from majority-owned operations	$ 2,095	$ 564	$ 54	$ (5)	$ 2,708
Operating Costs and Expenses					
Cost of majority-owned operations	1,600	435	37	(5)	2,067
Depreciation and amortization	133	51	10	—	194
General, administrative and development	39	31	127	—	197
Other charges					
Corporate relocation charges	—	—	6	—	6
Reorganization items	—	—	—	—	—
Impairment charges	6	—	—	—	6
Total operating costs and expenses	1,778	517	180	(5)	2,470
Operating Income/(Loss)	317	47	(126)	—	238
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	—	—	—	—
Equity in earnings of consolidated subsidiaries	101	—	274	(375)	—
Equity in earnings of unconsolidated affiliates	35	69	—	—	104
Write downs and gains/(losses) on sales of equity method investments	(47)	16	—	—	(31)
Other income, net	16	54	13	(21)	62
Refinancing expenses	—	10	(66)	—	(56)
Interest expense	(1)	(76)	(141)	21	(197)
Total other income/(expense)	104	73	80	(375)	(118)
Income/(Loss) From Continuing Operations Before Income Taxes	421	120	(46)	(375)	120
Income Tax Expense	155	18	(130)	—	43
Income From Continuing Operations	266	102	84	(375)	77
Income on Discontinued Operations, net of Income Taxes	5	2	—	—	7
Net Income	$ 271	$ 104	$ 84	$ (375)	$ 84

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEETS
December 31, 2005
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(1)]	Consolidated Balance
			(In millions)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ (7)	$ 91	$ 422	$ —	$ 506
Restricted cash	3	61	—	—	64
Accounts receivable-trade, net	214	275	(205)	—	284
Current portion of notes receivable	—	25	468	(468)	25
Taxes receivable	(2)	—	45	—	43
Inventory	232	27	1	—	260
Derivative instruments valuation	385	16	3	—	404
Collateral on deposit in support of energy risk management activities	438	—	—	—	438
Deferred income taxes	6	3	(5)	—	4
Prepayments and other current assets	65	22	38	—	125
Assets held for sale	8	—	35	—	43
Current assets — discontinued operations	—	1	—	—	1
Total current assets	1,342	521	802	(468)	2,197
Net property, plant and equipment	2,176	832	31	—	3,039
Other Assets					
Investment in subsidiaries	787	—	1,774	(2,561)	—
Equity investments in affiliates	243	360	—	—	603
Notes receivable	76	457	1,398	(1,473)	458
Intangible assets, net	238	19	—	—	257
Derivative instruments valuation	18	4	—	—	22
Funded letter of credit	—	—	350	—	350
Deferred income taxes	—	26	—	—	26
Other assets	22	20	83	—	125
Non-current assets — discontinued operations	—	354	—	—	354
Total other assets	1,384	1,240	3,605	(4,034)	2,195
Total Assets	$ 4,902	$ 2,593	$ 4,438	$ (4,502)	$ 7,431
LIABILITIES AND STOCK HOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt	$ 459	$ 96	$ 14	$ (468)	$ 101
Accounts Payable	158	89	21	—	268
Derivative instruments valuation	678	14	—	—	692
Other bankruptcy settlement	—	3	—	—	3
Accrued expenses and other current liabilities	60	48	69	—	177
Current liabilities — discontinued operations	—	115	—	—	115
Total current liabilities	1,355	365	104	(468)	1,356
Other Liabilities					
Long-term debt	1,397	791	1,866	(1,473)	2,581
Deferred income taxes	37	149	(51)	—	135
Derivative instruments valuation	25	92	20	—	137
Out-of-market contracts	298	—	—	—	298
Other long-term obligations	126	58	22	—	206
Non-current liabilities — discontinued operations	—	240	—	—	240
Total non-current liabilities	1,883	1,330	1,857	(1,473)	3,597
Total liabilities	3,238	1,695	1,961	(1,941)	4,953
Minority interest	—	1	—	—	1
3.625% Preferred Stock	—	—	246	—	246
Stockholders' Equity	1,664	897	2,231	(2,561)	2,231
Total Liabilities and Stockholders' Equity	$ 4,902	$ 2,593	$ 4,438	$ (4,502)	$ 7,431

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2005
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(1)]	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 271	$ 104	$ 84	$ (375)	$ 84
Adjustments to reconcile net income to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates and consolidated subsidiaries	(64)	(45)	453	(352)	(8)
Depreciation and amortization	133	52	10	—	195
Amortization of deferred financing costs and debt discount/(premium)	—	6	16	—	22
Write-off of deferred financing costs due to refinancing	—	(10)	2	—	(8)
Write downs and losses on sales of equity method investments	47	(16)	—	—	31
Deferred income taxes and investment tax credits	71	13	(82)	—	2
Unrealized (gains)/losses on derivatives	150	(10)	3	—	143
Minority interest	—	1	—	—	1
Amortization of intangible assets	(2)	19	—	—	17
Amortization of unearned equity compensation	3	1	8	—	12
Restructuring and impairment charges	6	—	—	—	6
Loss on sale and disposal of property, plant and equipment	4	—	—	—	4
Gain on sale of discontinued operations	(6)	—	—	—	(6)
Gain on TermRio settlement	—	(14)	—	—	(14)
Collateral deposit payments in support of energy risk management	(405)	—	—	—	(405)
Cash provided by(used by) changes in other working capital, net of dispositions affects	(421)	9	404	—	(8)
Net Cash Provided (Used) by Operating Activities	(213)	110	898	(727)	68
Cash Flows from Investing Activities					
Return of Capital from Subsidiaries	—	—	1,398	(1,398)	—
Inter-company Loans (I/C) to Subsidiaries	—	—	(2,181)	2,181	—
Proceeds from I/C loans with parent and subsidiaries	327	—	325	(652)	—
Proceeds from sale of discontinued operations	36	—	—	—	36
Proceeds from sale of investments	—	70	—	—	70
Proceeds from sale of property, plant and equipment	9	—	—	—	9
Return of capital/(Investments) in projects	—	2	—	—	2
Decrease/(increase) in restricted cash	1	44	—	—	45
Deferred acquisition costs	—	—	(5)	—	(5)
Decrease/(increase) in notes receivable	5	102	—	—	107
Capital expenditures	(78)	(22)	(6)	—	(106)
Net Cash Provided (Used) by Investing Activities	300	196	(469)	131	158
Cash Flows from Financing Activities					
Return of Capital Payments to Parent	(1,398)	—	—	1,398	—
Proceeds from Parent Inter-company Loans	2,181	—	—	(2,181)	—
Payments for Parent Inter-company Loans	(325)	(327)	—	652	—
Payments of dividends	(704)	(23)	(20)	727	(20)
Repayment of minority interest obligations	—	(4)	—	—	(4)
Accelerated share repurchase payment, net	—	—	(250)	—	(250)
Issuance of 3.625% Preferred Stock, net	—	—	246	—	246
Proceeds from issuance of long-term debt	—	249	—	—	249
Deferred debt issuance costs	—	—	(46)	—	(46)
Principal payments on long-term debt	(4)	(352)	(649)	—	(1,005)
Net Cash Provided (Used) by Financing Activities	(250)	(457)	(719)	596	(830)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(2)	—	—	(2)
Change in Cash from Discontinued Operations	—	8	—	—	8
Net Increase (Decrease) in Cash and Cash Equivalents	(163)	(145)	(290)	—	(598)
Cash and Cash Equivalents at Beginning of Period	156	236	712	—	1,104
Cash and Cash Equivalents at End of Period	$ (7)	$ 91	$ 422	$ —	$ 506

(1) All significant intercompany transactions have been eliminated in consolidation

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2004
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[1]	Consolidated Balance
			(In millions)		
Operating Revenues					
Revenues from majority-owned operations	$ 1,722	$ 582	$ 51	$ (7)	$ 2,348
Operating Costs and Expenses					
Cost of majority-owned operations	1,060	405	31	(7)	1,489
Depreciation and amortization	133	62	13	—	208
General, administrative and development	118	30	62	—	210
Other charges					
Corporate relocation charges	—	—	16	—	16
Reorganization items	2	—	(15)	—	(13)
Impairment charges	3	27	15	—	45
Total operating costs and expenses	1,316	524	122	(7)	1,955
Operating Income/(Loss)	406	58	(71)	—	393
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	—	—	—	—
Equity in earnings of consolidated subsidiaries	89	—	293	(382)	—
Equity in earnings of unconsolidated affiliates	92	69	(1)	—	160
Write downs and gains/(losses) on sales of equity method investments	(16)	(1)	1	—	(16)
Other income, net	7	35	5	(20)	27
Refinancing expenses	—	—	(72)	—	(72)
Interest expense	—	(104)	(182)	20	(266)
Total other income/(expense)	172	(1)	44	(382)	(167)
Income/(Loss) From Continuing Operations Before Income Taxes	578	57	(27)	(382)	226
Income Tax Expense/(Benefit)	238	44	(217)	—	65
Income/(Loss) From Continuing Operations	340	13	190	(382)	161
Income/(Loss) on Discontinued Operations, net of Income Taxes	3	26	(4)	—	25
Net Income	$ 343	$ 39	$ 186	$ (382)	$ 186

[1] All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEETS
December 31, 2004
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy,Inc. (Note Issuer)	Eliminations[1]	Consolidated Balance
			(In millions)		
		ASSETS			
Current Assets					
Cash and cash equivalents	$ 156	$ 236	$ 712	$ —	$ 1,104
Restricted cash	4	106	—	—	110
Accounts receivable-trade, net	183	80	7	—	270
Current portion of notes receivable	—	82	6	(3)	85
Income taxes receivable	—	(5)	42	—	37
Inventory	216	29	2	—	247
Derivative instruments valuation	80	—	—	—	80
Prepayments and other current assets	71	25	43	(3)	136
Collateral on deposit in support of energy risk management activities	33	—	—	—	33
Current assets — discontinued operations	—	17	—	—	17
Total current assets	743	570	812	(6)	2,119
Net property, plant and equipment	2,244	883	31	—	3,158
Other Assets					
Investment in subsidiaries	777	—	3,916	(4,693)	—
Equity investments in affiliates	327	408	—	—	735
Notes receivable, less current portion, less reserve	408	797	1	(642)	564
Intangible assets, net	256	38	—	—	294
Derivative instruments valuation	2	35	5	—	42
Funded letter of credit	—	—	350	—	350
Deferred income taxes	—	34	—	—	34
Other non- current assets	36	21	54	—	111
Non-current assets — discontinued operations	—	457	—	—	457
Total other assets	1,806	1,790	4,326	(5,335)	2,587
Total Assets	$ 4,793	$ 3,243	$ 5,169	$ (5,341)	$ 7,864
		LIABILITIES AND STOCK HOLDERS' EQUITY			
Current Liabilities					
Current portion of long-term debt and capital leases	$ —	$ 98	$ 416	$ (3)	$ 511
Accounts payable	427	(33)	(181)	1	214
Derivative instruments valuation	17	—	—	—	17
Other bankruptcy settlement	—	6	—	—	6
Accrued expenses and other current liabilities	101	31	37	(3)	166
Current liabilities — discontinued operations	—	173	—	—	173
Total current liabilities	545	275	272	(5)	1,087
Other Liabilities					
Long-term debt	—	1,487	2,128	(642)	2,973
Deferred income taxes	(32)	165	36	—	169
Derivative instruments valuation	—	132	16	—	148
Out-of-market contracts	319	—	—	—	319
Other non-current liabilities	122	40	25	—	187
Non-current liabilities — discontinued operations	—	288	—	—	288
Total non-current liabilities	409	2,112	2,205	(642)	4,084
Total liabilities	954	2,387	2,477	(647)	5,171
Minority interest	—	1	—	—	1
Stockholders' Equity	3,839	855	2,692	(4,694)	2,692
Total Liabilities and Stockholders' Equity	$ 4,793	$ 3,243	$ 5,169	$ (5,341)	$ 7,864

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2004
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[1]	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 343	$ 39	$ 186	$ (382)	$ 186
Adjustments to reconcile net income to net cash provided (used) by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates and consolidated subsidiaries	(53)	(38)	—	90	(1)
Depreciation and amortization	133	69	13	—	215
Reserve for note and interest receivable	7	5	—	—	12
Amortization of financing costs and debt discount/(premium)	—	21	7	—	28
Write-off of deferred financing costs and debt premium	—	—	42	—	42
Deferred income taxes and investment tax credits	26	(8)	118	(79)	57
Minority interest	—	1	—	—	1
Unrealized (gains)/losses on derivatives	(71)	(9)	6	—	(74)
Write downs and losses on sales of equity method investments	16	1	(1)	—	16
Amortization of intangibles	14	38	—	—	52
Amortization of unearned equity compensation	2	1	11	—	14
Collateral deposit payments in support of energy risk management	(7)	—	—	—	(7)
Restructuring and impairment charges	3	27	15	—	45
Loss from sale and disposal of property, plant and equipment	1	—	—	—	1
(Gain)/loss on sale of discontinued operations	(2)	(26)	5	—	(23)
Cash provided by provided (used) by changes in certain working capital items, net of effects from acquisitions and dispositions	(41)	1	126	(5)	81
Net Cash Provided (Used) by Operating Activities	371	122	528	(376)	645
Cash Flows from Investing Activities					
Proceeds from sale of discontinued operations	2	251	—	—	253
Proceeds from sale of investments	21	27	3	—	51
Proceeds from sale of property, plant and equipment	4	—	—	—	4
Decrease/(increase) in restricted cash	1	(28)	—	—	(27)
Decrease/(increase) in notes receivable	(23)	16	25	7	25
Capital expenditures	(82)	(28)	(9)	—	(119)
Investments in projects	4	(16)	9	—	(3)
Distributions/(investments) in subsidiaries	—	—	82	(82)	—
Net Cash Provided (Used) by Investing Activities	(73)	222	110	(75)	184
Cash Flows from Financing Activities					
Net borrowings under line of credit agreement					
Proceeds from issuance of preferred shares	—	—	406	—	406
Payment for treasury stock	—	—	(405)	—	(405)
Capital contributions from parent	10	33	—	(43)	—
Dividends and return of investment to NRG Energy, Inc.	(407)	(10)	—	417	—
Proceeds from issuance of long-term debt	—	(7)	1,304	36	1,333
Deferred debt issuance costs	—	—	(26)	—	(26)
Funded letter of credit	—	—	(100)	—	(100)
Principal payments on long-term debt	(41)	(292)	(1,200)	41	(1,492)
Net Cash Provided (Used) by Financing Activities	(438)	(276)	(21)	451	(284)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	3	—	—	3
Change in Cash from Discontinued Operations	—	6	—	—	6
Net Increase (Decrease) in Cash and Cash Equivalents	(140)	77	617	—	554
Cash and Cash Equivalents at Beginning of Period	296	159	95	—	550
Cash and Cash Equivalents at End of Period	$ 156	$ 236	$ 712	$ —	$ 1,104

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Period December 6, 2003 Through December 31, 2003
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[1]	Consolidated Balance
			(In millions)		
Operating Revenues					
Revenues from majority-owned operations	$ 94	$ 40	$ 3	$ —	$ 137
Operating Costs and Expenses					
Cost of majority-owned operations	64	29	2	—	95
Depreciation and amortization	7	4	1	—	12
General, administrative and development	7	3	3	—	13
Other Charges:					
Reorganization items	—	—	2	—	2
Total operating costs and expenses	78	36	8	—	122
Operating Income/(Loss)	16	4	(5)	—	15
Other Income (Expense)					
Equity in earnings of consolidated subsidiaries	3	—	17	(20)	—
Equity in earnings of unconsolidated affiliates	11	2	1	—	14
Interest expense	(6)	(5)	(8)	—	(19)
Total other income/(expense)	8	(3)	10	(20)	(5)
Income/(Loss) From Continuing Operations Before Income Taxes	24	1	5	(20)	10
Income Tax Expense/(Benefit)	4	1	(6)	—	(1)
Income/(Loss) From Continuing Operations	20	—	11	(20)	11
Income/(Loss) on Discontinued Operations, net of Income Taxes	—	—	—	—	—
	—	—	—	—	—
Net Income	$ 20	$ —	$ 11	$ (20)	$ 11

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Period December 6, 2003 Through December 31, 2003
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[1]	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income	$ 20	$ —	$ 11	$ (20)	$ 11
Adjustments to reconcile net income to net cash provided by operating activities Distributions in excess of (less than) equity earnings of unconsolidated affiliates	2	(2)	(18)	20	2
Depreciation and amortization	8	4	1	—	13
Amortization of deferred financing costs	—	—	1	—	1
Amortization of debt discount/(premium)	—	1	—	—	1
Deferred income taxes and investment tax credits	—	—	(4)	1	(3)
Current tax expense — non cash contribution from members	4	(3)	—	(1)	—
Unrealized (gains)/losses on derivatives	—	4	—	—	4
Minority interest	—	—	—	—	—
Amortization of intangibles	(16)	3	—	—	(13)
Collateral deposit payments in support of energy risk management	(8)	—	—	—	(8)
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions	(64)	—	(533)		(597)
Net Cash Provided (Used) by Operating Activities	(54)	7	(542)	—	(589)
Cash Flows from Investing Activities					
Investments in subsidiaries	—	—	(1,531)	1,531	—
Decrease/(increase) in restricted cash	343	32	—	—	375
Decrease/(increase) in notes receivable	1	(11)	(1)	12	1
Capital expenditures	(3)	(8)	—	—	(11)
Investments in projects	(2)	—	—	—	(2)
Net Cash Provided (Used) by Investing Activities	339	13	(1,532)	1,543	363
Cash Flows from Financing Activities					
Capital contributions from parent	1,531	—	—	(1,531)	—
Proceeds from issuance of long-term debt	—	—	2,450	—	2,450
Deferred debt issuance costs	—	—	(75)	—	(75)
Funded letter of credit	—	—	(250)	—	(250)
Principal payments on long-term debt	(1,714)	(6)	—	(12)	(1,732)
Net Cash Provided (Used) by Financing Activities	(183)	(6)	2,125	(1,543)	393
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(14)	—	—	(14)
Change in Cash from Discontinued Operations	—	1	—	—	1
Net Increase in Cash and Cash Equivalents	102	1	51	—	154
Cash and Cash Equivalents at Beginning of Period	194	158	44	—	396
Cash and Cash Equivalents at End of Period	$ 296	$ 159	$ 95	$ —	$ 550

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Period January 1, 2003 Through December 5, 2003
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(1)]	Consolidated Balance
			(In millions)		
Operating Revenues					
Revenues from majority-owned operations	$ 1,230	$ 522	$ 47	$ (1)	$ 1,798
Operating Costs and Expenses					
Cost of majority-owned operations	991	331	33	(1)	1,354
Depreciation and amortization	130	67	14	—	211
General, administrative and development	65	29	76	—	170
Other Charges:					
Reorganization charges	30	17	151	—	198
Impairment charges	248	(123)	112	—	237
Fresh start reporting adjustments	—	(101)	(6,571)	2,452	(4,220)
Fresh start reporting adjustments — subsidiaries	—	—	2,452	(2,452)	—
Legal settlement	(9)	4	468	—	463
Total operating costs and expenses	1,455	224	(3,265)	(1)	(1,587)
Operating Income/(Loss)	(225)	298	3,312	—	3,385
Other Income (Expense)					
Equity in earnings of consolidated subsidiaries	105	—	(18)	(87)	—
Equity in earnings of unconsolidated affiliates	107	65	(1)	—	171
Write downs and losses on sales of equity method investments	(16)	(126)	(5)	—	(147)
Other income, net	5	30	(15)	(1)	19
Interest expense	(136)	(61)	(112)	1	(308)
Total other income/(expense)	65	(92)	(151)	(87)	(265)
Income/(Loss) From Continuing Operations Before Income Taxes	(160)	206	3,161	(87)	3,120
Income Tax Expense/(Benefit)	(107)	(11)	156	—	38
Income/(Loss) From Continuing Operations	(53)	217	3,005	(87)	3,082
Income/(Loss) on Discontinued Operations, net of Income Taxes	(26)	(51)	(239)	—	(316)
Net Income/(Loss)	$ (79)	$ 166	$ 2,766	$ (87)	$ 2,766

(1) All significant intercompany transactions have been eliminated in consolidation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOW
For the Period January 1, 2003 through December 5, 2003
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[1]	Consolidated Balance
			(In millions)		
Cash Flows from Operating Activities					
Net income/(loss)	$ (79)	$ 166	$ 2,766	$ (87)	$ 2,766
Adjustments to reconcile net income/(loss) to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	(95)	(54)	21	87	(41)
Depreciation and amortization	131	112	14	—	257
Amortization of deferred financing costs	7	7	4	—	18
Write downs and losses on sales of equity method investments	16	131	—	—	147
Deferred income taxes and investment tax credits	(123)	(36)	181	(24)	(2)
Current tax expense — non cash contribution from members	(17)	(54)	—	71	—
Unrealized (gains)/losses on derivatives	(13)	(75)	29	24	(35)
Minority interest	—	2	—	—	2
Restructuring and impairment charges	273	94	41	—	408
Fresh start reporting adjustments	—	—	(3,895)	—	(3,895)
Gain on sale of discontinued operations	3	(198)	9	—	(186)
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions	348	2	658	(209)	799
Net Cash Provided (Used) by Operating Activities	451	97	(172)	(138)	238
Cash Flows from Investing Activities					
Investment in subsidiaries	—	—	129	(129)	—
Proceeds from sale of discontinued operations	—	19	—	—	19
Proceeds from sale of investments	—	107	—	—	107
Proceeds from sale of turbines	—	—	71	—	71
(Increase) in trust funds	(14)	—	—	—	(14)
Decrease/(increase) in restricted cash	(198)	(54)	—	—	(252)
Decrease/(increase) in notes receivable	98	42	—	(142)	(2)
Capital expenditures	(56)	(7)	(51)	—	(114)
Investments in projects	(4)	(5)	8	—	(1)
Net Cash Provided (Used) by Investing Activities	(174)	102	157	(271)	(186)
Cash Flows from Financing Activities					
Capital contributions from parent	(135)	(132)	—	267	—
Proceeds from issuance of long-term debt	—	40	—	—	40
Deferred debt issuance costs	(8)	(1)	(10)	—	(19)
Principal payments on long-term debt	(4)	(189)	—	142	(51)
Net Cash Provided (Used) by Financing Activities	(147)	(282)	(10)	409	(30)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(22)	—	—	(22)
Change in Cash from Discontinued Operations	—	35	—	—	35
Net Increase in Cash and Cash Equivalents	130	(70)	(25)	—	35
Cash and Cash Equivalents at Beginning of Period	64	228	69	—	361
Cash and Cash Equivalents at End of Period	$ 194	$ 158	$ 44	$ —	$ 396

(1) All significant intercompany transactions have been eliminated in consolidation.

Note 34 — Subsequent Events

Texas Genco Acquisition

On February 2, 2006, NRG acquired Texas Genco LLC, a Delaware limited liability company, by purchasing all of the outstanding equity interests in Texas Genco pursuant to the Acquisition Agreement, dated September 30, 2005, by and among NRG, Texas Genco and the Sellers. The purchase price of approximately $6.1 billion consisted of approximately $4.4 billion in cash and the issuance of approximately 35.4 million shares of NRG's common stock valued at $1.7 billion. This amount is subject to adjustment due to acquisition costs. The value of our common stock issued to the Sellers was based on our average stock price immediately before and after the closing date of February 2, 2006. The Acquisition includes the assumption of approximately $2.7 billion of Texas Genco debt. Texas Genco is now a wholly-owned subsidiary of NRG, and will be managed and accounted for as a new business segment to be referred to as NRG Texas.

The acquisition of Texas Genco was partially funded at closing with the combination of (i) cash proceeds received upon the issuance and sale in a public offering of 20,855,057 shares of our common stock at a price of $48.75 per share; (ii) cash proceeds received upon the issuance and sale of $1.2 billion aggregate principal amount of 7.25% Senior Notes due 2014 and $2.4 billion aggregate principal amount of 7.375% Senior Notes due 2016, as described below; (iii) cash proceeds received upon the issuance and sale in a public offering of 2 million shares of mandatory convertible preferred stock at a price of $250 per share, as described below; (iv) funds borrowed under a new senior secured credit facility consisting of a $3.575 billion term loan facility, a $1.0 billion revolving credit facility and a $1.0 billion synthetic letter of credit facility, as described below; and (v) cash on hand.

Texas Genco owns approximately 11,000 MW of net operating generation capacity, and sells power and related services in ERCOT.

The acquisition of Texas Genco will be accounted for using the purchase method of accounting and, accordingly, the purchase price will be allocated to the assets acquired and liabilities assumed based on the estimated fair value of such assets and liabilities as of February 2, 2006. As it is difficult to estimate an allocation of purchase price without completed asset appraisals, we have made a preliminary allocation estimate. Ultimately, the excess of the purchase price over the fair value of the net tangible and identified intangible assets acquired will be recorded as goodwill. The allocation of the purchase price may be adjusted if additional information on known contingencies existing at the date of acquisition becomes available within one year after the acquisition, and longer for certain income tax items.

The following table summarizes the estimated unaudited fair value of the assets acquired and liabilities assumed at the date of acquisition. For purposes of acquisition costs, we have estimated such costs at approximately $126 million, increasing the total purchase price to approximately $6.2 billion We are in the process of obtaining appraisals of the fixed assets, intangibles and certain liabilities acquired; thus, the allocation of the purchase price is subject to refinement.

	February 2, 2006 (Unaudited) (In millions)
Current and non-current assets	$ 1,408
Property, Plant and equipment	7,745
Intangibles	1,160
Goodwill	2,664
Total assets acquired	12,977
Current and non-current liabilities	1,004
Out of market contracts	3,048
Long term debt	2,735
Total liabilities acquired	6,787
Net assets acquired	$ 6,190

Based on our preliminary allocation of the purchase price, the purchase price will include an allocation to certain intangibles as well as goodwill. The known intangibles include emission allowances and the fair value for positive power contracts totaling $1,140 million and $20 million, respectively. The weighted average amortization period for the emission allowances and the positive power contracts is approximately 26 years and one year, respectively — a weighted average of approximately 26 years for total intangible assets.

The allocation also includes a material value for out-of-market contracts assumed at the closing of the acquisition which will be amortized over the next four years on a weighted average basis. When amortized, this balance will be reflected as an increase to our revenue.

Cash Tender Offer and Consent Solicitation

On December 15, 2005, we commenced a cash tender offer and consent solicitation for any and all outstanding $1.1 billion aggregate principal amount of our 8% Second Priority Notes. On such date, we also commenced a cash tender offer and consent solicitation for any and all outstanding $1.1 billion aggregate principal amount of Texas Genco LLC's and Texas Genco Financing Corp.'s 6.875% senior notes due 2014, or the Texas Genco Notes. The offer to purchase the Second Priority Notes and the Texas Genco Notes was part of our previously announced financing plan in connection with our acquisition of Texas Genco. As of February 2, 2006, NRG had received valid tenders from holders in aggregate principal amount of the NRG Notes, representing approximately 99.96% of the outstanding Second Priority Notes, and had received valid tenders from holders of the $1.1 billion in aggregate principal amount of the Texas Genco Notes, representing 100% of the outstanding Texas Genco Notes. The purchase price for the Second Priority Notes totaling approximately $1.2 billion was paid by NRG on February 2, 2006 and the purchase price for the Texas Genco Notes totaling approximately $1.2 billion was paid by NRG on February 3, 2006.

New Financings

New Senior Credit Facility

On February 2, 2006, we also entered into a new senior secured credit facility with a syndicate of financial institutions, including Morgan Stanley Senior Funding, Inc., as administrative agent, Morgan Stanley & Co. Inc., as collateral agent, and Morgan Stanley Senior Funding, Inc. and Citigroup Global Markets Inc. as joint lead book-runners, joint lead arrangers and co-documentation agents providing for up to an aggregate amount of $5.575 billion, or the New Senior Credit Facility, consisting of a $3.575 billion senior first priority secured term loan facility, or the Term Loan Facility, a $1.0 billion senior first priority secured revolving credit facility, or the Revolving Credit Facility, and a $1.0 billion senior first priority secured synthetic letter of credit facility, or the Letter of Credit Facility. The New Senior Credit Facility replaced our then existing senior secured credit facility. The Term Loan Facility will mature on February 1, 2013 and will amortize in 27 consecutive equal quarterly installments of 0.25% of the original principal amount of the Term Loan Facility during the first six and 3/4 years thereof with the balance payable on the seventh anniversary thereof. The full amount of the Revolving Credit Facility will mature on February 2, 2011. The Letter of Credit Facility will mature on February 1, 2013 and no amortization will be required in respect thereof.

The New Senior Credit Facility is guaranteed by substantially all of our existing and future direct and indirect subsidiaries, with certain customary or agreed-upon exceptions for unrestricted foreign subsidiaries, project subsidiaries and certain other subsidiaries. In addition, the New Senior Credit Facility is secured by liens on substantially all of our assets and the assets of our subsidiaries, with certain customary or agreed-upon exceptions for unrestricted foreign subsidiaries, project subsidiaries and certain other subsidiaries. The capital stock of substantially all of our subsidiaries, with certain exceptions for unrestricted subsidiaries, foreign subsidiaries and project subsidiaries, has been pledged for the benefit of the New Senior Credit Facility lenders.

The New Senior Credit Facility is also secured by a first-priority perfected security interest in all of the property and assets owned at-any time or acquired by us and our subsidiaries, other than certain other limited exceptions. These exceptions include assets such as the assets of certain unrestricted subsidiaries, equity interests in certain of our project affiliates that have non-recourse debt financing, and voting equity interests in excess of 66% of the total outstanding voting equity interest of certain of our foreign subsidiaries.

The New Senior Credit Facility contains customary covenants, which, among other things require us to meet certain financial tests, including a minimum interest coverage ratio and a maximum leverage ratio, each at the corporate level and on a consolidated basis, and limit's our ability to:

- incur indebtedness and liens and enter into sale and lease-back transactions;
- make investments,
- loans and advances;
- engage in mergers, acquisitions consolidations and asset sales;
- pay dividends and other restricted payments;
- enter into transactions with affiliates;
- engage in business activities and hedging transactions;
- make capital expenditures;
- make debt payments;
- make certain changes to the terms of material indebtedness;
- and other covenants customary for such facilities.

In anticipation of the New Senior Credit Facility, in January 2006, we entered into a series of new interest rate swaps. These interest rate swaps became effective on February 15, 2006 and are intended to hedge the risk associated with floating interest rates. For each of the interest rate swaps, we pay our counterparty the equivalent of a fixed interest payment on a predetermined notional value, and we receive quarterly the equivalent of a floating interest payment based on 3-month LIBOR calculated on the same notional value. All payments by us and our counterparties are made quarterly, and the LIBOR is determined in advance of each interest period. While the notional value of each of the swaps does not vary over time, the swaps are designed to mature sequentially. The total notional amount of these swaps as of February 25, 2006 was $2.15 billion. The notional amounts and maturities of each tranche of these swaps are as follows:

Period of swap	Notional Value	Maturity
1-year	$120 million	March 31, 2007
2-year	$140 million	March 31, 2008
3-year	$150 million	March 31, 2009
4-year	$190 million	March 31, 2010
5-year	$1.55 billion	March 31, 2011

Senior Notes

On February 2, 2006, we completed the sale of (i) $1.2 billion aggregate principal amount of 7.25% senior notes due 2014, or 7.25% Senior Notes, and (ii) $2.4 billion aggregate principal amount of 7.375% senior notes due 2016, or 7.375% Senior Notes, collectively the Senior Notes. The Senior Notes were issued under an Indenture, dated February 2, 2006, or the Indenture, between us and Law Debenture Trust Company of New York, as trustee, or the Trustee, as supplemented by a First Supplemental Indenture, dated February 2, 2006, or the First Supplemental Indenture, between us, the guarantors named therein and the Trustee, relating to the 7.25% Senior Notes, and as supplemented by a Second Supplemental Indenture, dated February 2, 2006, or the Second Supplemental Indenture (together with the Indenture and the First Supplemental Indenture, the Indentures) between us, the guarantors named therein and the Trustee, relating to the 7.375% Senior Notes. The Indentures and the form of notes, provide, among other things, that the Senior Notes will be senior unsecured obligations of NRG.

Interest is payable on the Senior Notes on February 1 and August 1 of each year beginning on August 1, 2006 until their maturity dates — February 1, 2014 for the 7.25% Senior Notes and February 1, 2016 for the 7.375% Senior Notes.

Prior to February 1, 2010 for the 7.25% Senior Notes and prior to February 1, 2011 for the 7.375% Senior Notes, we may redeem all or a portion of the series of Senior Notes at a price equal to 100% of the principal amount plus a "make whole" premium and accrued interest. On or after February 1, 2010 for the 7.25% Senior Notes and on or after February 1, 2011 for the 7.375% Senior Notes, we may redeem all or a portion of the series of Senior Notes at redemption prices set forth in the Indentures. In addition, at any time prior to February 1, 2009, we may redeem up to 35% of the aggregate principal amount of the series of Senior Notes with the net proceeds of certain equity offerings at the redemption price set forth in the Indentures.

The terms of the Indentures, among other things, limit our ability and certain of our subsidiaries' ability to:

- make restricted payments;
- restrict dividends or other payments of subsidiaries;
- incur additional debt;
- engage in transactions with affiliates;
- create liens on assets;
- engage in sale and leaseback transactions;
- and consolidate, merge or transfer all or substantially all of its assets and the assets of its subsidiaries.

The Indentures provide for customary events of default which include, among others, nonpayment of principal or interest; breach of other agreements in the Indentures; defaults in failure to pay certain other indebtedness; the rendering of judgments to pay certain amounts of money against us and our subsidiaries; the failure of certain guarantees to be enforceable; and certain events of bankruptcy or insolvency. Generally, if an event of default occurs, the Trustee or the holders of at least 25% in principal amount of the then outstanding series of Senior Notes may declare all the Senior Notes of such series to be due and payable immediately.

5.75% Preferred Stock

On February 2, 2006, we completed the issuance of 2 million shares of 5.75% mandatory convertible preferred stock, or the 5.75% Preferred Stock, at an offering price of $250 per share for total net proceeds after deducting offering expenses and underwriting discounts of approximately $486 million. Dividends on the 5.75% Preferred Stock are $14.375 per share per year, and are due and payable on a quarterly basis beginning on March 15, 2006. The 5.75% Preferred Stock will automatically convert into common stock on March 16, 2009, or the Conversion Date, at a rate that is dependent upon the applicable market value of our common stock. If the applicable market value of our common stock is $60.45 a share or higher at the Conversion Date, then the 5.75% Preferred Stock is convertible at a rate of 4.1356 shares of our common stock for every share of 5.75% Preferred Stock outstanding. If the applicable market value of our common stock is less than or equal to $48.75 per share at the Conversion Date, then the 5.75% Preferred Stock is convertible at a rate of 5.1282 shares of our common stock for every share of 5.75% Preferred Stock outstanding. If the applicable market value of our common stock is between $48.75 per share and $60.45 per share at the Conversion Date, then the Mandatory Convertible Preferred Stock is convertible into common stock at a rate that is between 4.1356 per share and 5.1282 per share of common stock.

Common Stock

On January 31, 2006, we completed the issuance of 20,855,057 shares of our common stock, or the Common Stock, at an offering price of $48.75 per share for total net proceeds after deducting offering expenses and underwriting discounts of approximately $986 million.

Second Lien Structure

Before the Acquisition, Texas Genco's capital structure permitted the grant of second priority liens on its assets as security for their obligations under certain long-term power sales agreements and related hedges. The Credit Agreement for the New Senior Credit Facility and the Indentures, which became effective as of February 2, 2006, allow these arrangements to remain in place. In addition, the new debt instruments also permit us to grant second priority liens on our other assets in the United States in order to secure obligations under power sales agreements and related hedges, within certain limits. The seven trading counterparties of Texas Genco who held second priority liens on Texas Genco's assets as of February 2, 2006 have been offered a second priority lien on NRG's other assets under the new structure as additional collateral. Going forward, NRG anticipates that it will use the second lien structure to reduce the amount of cash collateral and letters of credit that it may otherwise be required to post from time to time to support its obligations under long term power sales and related hedges.

Bourbonnais Settlement

On January 31, 2006, we finalized a settlement agreement and stipulation, or the Agreements, with an equipment manufacturer related to turbine purchase agreements entered into in 2001 by NRG Bourbonnais and in 1999 by an undeveloped project. The Agreements provide for the payment of the equipment manufacturer's proof of claim previously filed in NRG's bankruptcy proceeding, a separate $6 million payment to the equipment manufacturer, and the release of all remaining claims the parties have against each other under the contracts. Additionally, NRG will receive certain equipment as well as a one year option to purchase new-build equipment for a fixed price. As a result of the Agreements, during the first quarter of 2006, NRG will reverse into income accounts payable totaling $35 million resulting from the discharge of the previously recorded liability. In addition, upon the transfer of title for the equipment noted above, NRG will record an adjustment to write up the value of the equipment received to fair value. We expect title to transfer in April 2006 at which time we will record a credit to income for the difference between our current book value and fair value received.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENT SCHEDULE

To the Board of Directors and Stockholders of NRG Energy, Inc.:

Our audit of the consolidated financial statements referred to in our report dated March 10, 2004, except as to Notes 6, 21, and 33, which are as of December 6, 2004, appearing in this Annual Report on Form 10-K also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Annual Report on Form 10-K. In our opinion, this financial statement schedule for the period from December 6, 2003 to December 31, 2003 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 10, 2004, except as to
Notes 6, 21, and 33,
which are as of December 6, 2004.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENT SCHEDULE

To the Board of Directors and Stockholders of NRG Energy, Inc.:

Our audits of the consolidated financial statements referred to in our report dated March 10, 2004, except as to Notes 6, 21, and 33, which are as of December 6, 2004, appearing in this Annual Report on Form 10-K also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Annual Report on Form 10-K. In our opinion, this financial statement schedule for the period from January 1, 2003 to December 5, 2003 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 10, 2004, except as to
Notes 6, 21, and 33,
which are as of December 6, 2004.

NRG ENERGY, INC.

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2005, 2004, and 2003

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(In millions)		
Allowance for doubtful accounts, deducted from accounts receivable in the balance sheet:					
Reorganized NRG					
Year ended December 31, 2005	$ 1	$ 2	$ —	$ (1)	$ 2
Year ended December 31, 2004	—	1	—	—	1
December 6 - December 31, 2003	—	—	—	—	—
Predecessor Company					
January 1 - December 5, 2003	18	16	—	(34)	—*
Income tax valuation allowance, deducted from deferred tax assets in the balance sheet:					
Reorganized NRG					
Year ended December 31, 2005	$ 708	$ 22	$ 85	$ (59)	$ 756
Year ended December 31, 2004	1,241	—	(277)	(256)	708
December 6 - December 31, 2003	1,242	(1)	—	—	1,241
Predecessor Company					
January 1 - December 5, 2003	1,171	71	—	—	1,242*

* December 6, 2003 - Fresh Start Balance

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NRG ENERGY, INC.
(Registrant)

/s/ DAVID W. CRANE

David W. Crane,
Chief Executive Officer
(Principal Executive Officer)

/s/ ROBERT C. FLEXON

Robert C. Flexon,
Chief Financial Officer
(Principal Financial Officer)

/s/ JAMES J. INGOLDSBY

James J. Ingoldsby,
Controller
(Principal Accounting Officer)

Date: March 7, 2006

POWER OF ATTORNEY:

Each person whose signature appears below constitutes and appoints David W. Crane, Timothy W. J. O'Brien and Tanuja M. Dehne, each or any of them, such person's true and lawful attorney-in-fact and agent with full power of substitution and resubstitution for such person and in such person's name, place and stead, in any and all capacities, to sign any and all amendments to this report on Form 10-K, and to file the same with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing necessary or desirable to be done in and about the premises, as fully to all intents and purposes as such person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or his or their substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

In accordance with the Exchange Act, this report has been signed by the following persons on behalf of the registrant in the capacities indicated on March 7, 2006.

Signature	Title	Date
/s/ DAVID W. CRANE David W. Crane	President and Chief Executive Officer	March 7, 2006
/s/ HOWARD E. COSGROVE Howard E. Cosgrove	Chairman of the Board	March 7, 2006
/s/ JOHN F. CHLEBOWSKI John F. Chlebowski	Director	March 7, 2006
/s/ LAWRENCE S. COBEN Lawrence S. Coben	Director	March 7, 2006
/s/ STEPHEN L. CROPPER Stephen L. Cropper	Director	March 7, 2006
/s/ MAUREEN MISKOVIC Maureen Miskovic	Director	March 7, 2006
/s/ ANNE C. SCHAUMBURG Anne C. Schaumburg	Director	March 7, 2006
/s/ HERBERT H. TATE Herbert H. Tate	Director	March 7, 2006
/s/ THOMAS H. WEIDEMEYER Thomas H. Weidemeyer	Director	March 7, 2006
/s/ WALTER R. YOUNG Walter R. Young	Director	March 7, 2006

EXHIBIT INDEX

2.1	Third Amended Joint Plan of Reorganization of NRG Energy, Inc., NRG Power Marketing, Inc., NRG Capital LLC, NRG Finance Company I LLC, and NRGenerating Holdings (No. 23) B.V.(7)
2.2	First Amended Joint Plan of Reorganization of NRG Northeast Generating LLC (and certain of its subsidiaries), NRG South Central Generating (and certain of its subsidiaries) and Berrians I Gas Turbine Power LLC.(7)
2.3	Acquisition Agreement, dated as of September 30, 2005, by and among NRG Energy, Inc., Texas Genco LLC and the Direct and Indirect Owners of Texas Genco LLC.(16)
3.1	Amended and Restated Certificate of Incorporation.(21)
3.2	Amended and Restated By-Laws.(8)
3.3	Certificate of Designation of 4.0% Convertible Perpetual Preferred Stock, as filed with the Secretary of State of the State of Delaware on December 20, 2004.(10)
3.4	Certificate of Designations of 3.625% Convertible Perpetual Preferred Stock, as filed with the Secretary of State of the State of Delaware on August 11, 2005. (22)
3.5	Certificate of Designations of 5.75% Mandatory Convertible Preferred Stock, as filed with the Secretary of State of the State of Delaware on January 27, 2006. (24)
4.1	Supplemental Indenture dated as of December 30, 2005, among NRG Energy, Inc., the subsidiary guarantors named on Schedule A thereto and Law Debenture Trust Company of New York, as trustee. (18)
4.2	Amended and Restated Common Agreement among XL Capital Assurance Inc., Goldman Sachs Mitsui Marine Derivative Products, L.P., Law Debenture Trust Company of New York, as Trustee, The Bank of New York, as Collateral Agent, NRG Peaker Finance Company LLC and each Project Company Party thereto dated as of January 6, 2004, together with Annex A to the Common Agreement.(2)
4.3	Amended and Restated Security Deposit Agreement among NRG Peaker Finance Company, LLC and each Project Company party thereto, and the Bank of New York, as Collateral Agent and Depositary Agent, dated as of January 6, 2004.(2)
4.4	NRG Parent Agreement by NRG Energy, Inc. in favor of the Bank of New York, as Collateral Agent, dated as of January 6, 2004.(2)
4.5	Indenture dated June 18, 2002, between NRG Peaker Finance Company LLC, as Issuer, Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Rockford LLC, NRG Rockford II LLC and Sterlington Power LLC, as Guarantors, XL Capital Assurance Inc., as Insurer, and Law Debenture Trust Company, as Successor Trustee to the Bank of New York.(4)
4.6	Registration Rights Agreement, dated December 21, 2004, by and among NRG Energy, Inc., Citigroup Global Markets Inc. and Deutsche Bank Securities Inc.(9)
4.7	Specimen of Certificate representing common stock of NRG Energy, Inc.(25)
4.8	Indenture, dated February 2, 2006, among NRG Energy, Inc. and Law Debenture Trust Company of New York.(26)
4.9	First Supplemental Indenture, dated February 2, 2006, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.250% Senior Notes due 2014. (26)
4.10	Second Supplemental Indenture, dated February 2, 2006, among NRG Energy, Inc., the guarantors named therein and Law Debenture Trust Company of New York as Trustee, re: NRG Energy, Inc.'s 7.375% Senior Notes due 2016. (26)
4.11	Form of 7.250% Senior Note due 2014.(26)
4.12	Form of 7.375% Senior Note due 2016.(26)
10.1*	Employment Agreement, dated November 10, 2003, between NRG Energy, Inc. and David Crane.(2)
10.2	Note Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc. and each of the purchasers named therein.(5)

10.3 Master Shelf and Revolving Credit Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc., The Prudential Insurance Registrants of America and each Prudential Affiliate, which becomes party thereto.(5)

10.4 Asset Sales Agreement, dated December 23, 1998, between NRG Energy, Inc., and Niagara Mohawk Power Corporation.(6)

10.5 Amendment to the Asset Sales Agreement, dated June 11, 1999, between NRG Energy, Inc., and Niagara Mohawk Power Corporation.(6)

10.6* Severance Agreement between NRG Energy, Inc. and George Schaefer dated December 18, 2002.(4)

10.7* Severance Agreement between NRG Energy, Inc. and John P. Brewster dated July 23, 2003.(2)

10.8 Stock Purchase Agreement dated December 13, 2004, by and among NRG Energy, Inc. and MatlinPatterson Global Advisers LLC, MatlinPatterson Global Opportunities Partners, L.P. and MatlinPatterson Global Opportunities Partners (Bermuda) L.P.(11)

10.9* NEO 2004 AIP Payout and 2005 Base Salary Table.(8)

10.10* Form of NRG Energy Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Officers and Key Management.(20)

10.11* Form of NRG Energy Inc. Long-Term Incentive Plan Deferred Stock Unit Agreement for Directors.(20)

10.12* NRG Energy, Inc. Long-Term Incentive Plan.(15)

10.13* Form of NRG Energy, Inc. Long-Term Incentive Plan Non-Qualified Stock Option Agreement.(12)

10.14* Form of NRG Energy, Inc. Long-Term Incentive Plan Restricted Stock Unit Agreement.(12)

10.15* Form of NRG Energy, Inc. Long Term Incentive Plan Performance Unit Agreement. (17)

10.16* Annual Incentive Plan for Designated Corporate Officers.(13)

10.17* Letter Agreement, dated March 5, 2004, between NRG Energy, Inc. and John P. Brewster.(14)

10.18* Letter Agreement, dated March 5, 2004, between NRG Energy, Inc. and Timothy W. O'Brien.(14)

10.19* Letter Agreement, dated February 19, 2004, between NRG Energy, Inc. and Robert C. Flexon.(14)

10.20 Railroad Car Full Service Master Leasing Agreement, dated as of February 18, 2005, between General Electric Railcar Services Corporation and NRG Power Marketing Inc.(20)

10.21 Commitment Letter, dated February 18, 2005, between General Electric Railcar Services Corporation and NRG Power Marketing Inc.(20)

10.22* Summary of Director Compensation.(20)

10.23 Purchase Agreement (West Coast Power) dated as of December 27, 2005, by and among NRG Energy, Inc., NRG West Coast LLC (Buyer), DPC II Inc. (Seller) and Dynegy, Inc.(19)

10.24 Purchase Agreement (Rocky Road Power), dated as of December 27, 2005, by and among Termo Santander Holding, L.L.C. (Buyer), Dynegy, Inc., NRG Rocky Road LLC (Seller) and NRG Energy, Inc.(19)

10.25* August 1, 2005 Executive Officer Grant Table.(23)

10.26* Letter Agreement, dated June 21, 2005, between NRG Energy, Inc. and Kevin T. Howell. (23)

10.27 Stock Purchase Agreement, dated as of August 10, 2005, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.(22)

10.28 Accelerated Share Repurchase Agreement, dated as of August 11, 2005, by and between NRG Energy, Inc. and Credit Suisse First Boston Capital LLC.(22)

10.29 Credit Agreement, dated February 2, 2006, among NRG, the lenders party thereto, Morgan Stanley Senior Funding, Inc., as administrative agent, Morgan Stanley Senior Funding, Inc. and Citigroup Global Markets Inc., as joint lead Book Runners, Joint Lead Arrangers and Co-Documentation Agents, Morgan Stanley & Co. Incorporated, as Collateral Agent, and Citigroup Global Markets Inc., as Syndication Agent.(26)

10.30	Investor Rights Agreement, dated as of February 2, 2006, by and among NRG Energy, Inc. and Certain Stockholders of NRG Energy, Inc. set forth therein.(27)
10.31	Amended and Restated Master Power Purchase and Sale Agreement, dated February 2, 2006, by and between J. Aron & Company and Texas Genco II, LP (including the cover sheet and confirmation letter thereto) (portions of this document have been omitted pursuant to a request for confidential treatment and filed separately with the SEC).(1)
10.32	Terms and Conditions of Sale, dated as of October 5, 2005, between Texas Genco II LP and FreightCar America, Inc., (including the Proposal Letter and Amendment thereto) (portions of this document have been omitted pursuant to a request for confidential treatment and filed separately with the SEC).(1)
10.33*	Employment Agreement, dated March 3, 2006, between NRG Energy, Inc. and David Crane.(1)
10.34*	NEO 2005 AIP Payout and 2006 Base Salary Table.(1)
21	Subsidiaries of NRG Energy. Inc.(1)
23.1	Consent of KPMG LLP.(1)
23.2	Consent of PricewaterhouseCoopers LLP.(1)
31.1	Rule 13a-14(a)/15d-14(a) certification of David W. Crane.(1)
31.2	Rule 13a-14(a)/15d-14(a) certification of Robert C. Flexon.(1)
31.3	Rule 13a-14(a)/15d-14(a) certification of James J. Ingoldsby.(1)
32	Section 1350 Certification.(1)

---

* Exhibit relates to compensation arrangements.

(1) Filed herewith.

(2) Incorporated herein by reference to NRG Energy, Inc.'s annual report on Form 10-K filed on March 16, 2004.

(3) Incorporated herein by reference to NRG Energy Inc.'s Amendment No. 2 to its annual report on Form 10-K filed on November 3, 2004.

(4) Incorporated herein by reference to NRG Energy, Inc.'s annual report on Form 10-K filed on March 31, 2003.

(5) Incorporated herein by reference to NRG Energy Inc.'s Registration Statement on Form S-1, as amended, Registration No. 333-33397.

(6) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended June 30, 1999.

(7) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on November 19, 2003.

(8) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on March 3, 2005.

(9) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on December 27, 2004.

(10) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on December 27, 2004.

(11) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K/A filed on December 14, 2004.

(12) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended September 30, 2004.

(13) Incorporated herein by reference to NRG Energy, Inc.'s 2004 proxy statement on Schedule 14A filed on July 12, 2004.

(14) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended March 31, 2004.

(15) Incorporated herein by reference to NRG Energy Inc.'s Registration Statement on Form S-8, Registration No. 333-114007.

(16) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on October 3, 2005.

(17) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended June 30, 2005.

(18) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on January 4, 2006.

(19) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on December 28, 2005.

(20) Incorporated herein by reference to NRG Energy, Inc.'s annual report on Form 10-K filed on March 30, 2005.

(21) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on May 24, 2005.

(22) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on August 11, 2005.

(23) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on August 3, 2005.

(24) Incorporated herein by reference to NRG Energy, Inc.'s Form 8-A filed on January 27, 2006.

(25) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on January 27, 2006.

(26) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on February 6, 2006.

(27) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on February 8, 2006.

EXHIBIT 31.1

CERTIFICATION

I, David W. Crane, certify that:

1. I have reviewed this annual report on Form 10-K of NRG Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DAVID W. CRANE

David W. Crane
Chief Executive Officer
(Principal Executive Officer)

Date: March 7, 2006

EXHIBIT 31.2

CERTIFICATION

I, Robert C. Flexon, certify that:

1. I have reviewed this annual report on Form 10-K of NRG Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ROBERT C. FLEXON

Robert C. Flexon
Chief Financial Officer
(Principal Financial Officer)

Date: March 7, 2006

EXHIBIT 31.3

CERTIFICATION

I, James J. Ingoldsby, certify that:

1. I have reviewed this annual report on Form 10-K of NRG Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JAMES J. INGOLDSBY

James J. Ingoldsby
Controller
(Principal Accounting Officer)

Date: March 7, 2006

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of NRG Energy, Inc. (the Company) on Form 10-K for the year ended December 31, 2005, as filed with the Securities and Exchange Commission on the date hereof (Form 10-K), each of the undersigned officers of the Company certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company as of the dates and for the periods expressed in the Form 10-K.

Date: March 7, 2006

/s/ DAVID W. CRANE

David W. Crane,
Chief Executive Officer
(Principal Executive Officer)

/s/ ROBERT C. FLEXON

Robert C. Flexon
Chief Financial Officer
(Principal Financial Officer)

/s/ JAMES J. INGOLDSBY

James J. Ingoldsby
Controller
(Principal Accounting Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to NRG Energy, Inc. and will be retained by NRG Energy, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.